ENVIRONMENTAL ASSESSMENT BOARD

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 19

DATE: Monday, May 27, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

EARR & ASSOCIATES REPORTING INC.

(416) 482-3277

2300 Yonge St., Suite 709 Toronto, Canada M4P 1E4

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Monday, the 27th day of May, 1991, commencing at 10:00 a.m.

VOLUME 19

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

S T A F F :

MR. M. HARPUR	Board Counsel
MR. R. NUNN	Counsel/Manager, Informations Systems
MS. C. MARTIN	Administrative Coordinator
MS. G. MORRISON	Executive Coordinator

A P P E A R A N C E S

B. CAMPBELL L. FORMUSA B. HARVIE	)))	ONTARIO HYDRO
J.C. SHEPHERD I. MONDROW	))	IPPSO
R. WATSON A. MARK	))	MUNICIPAL ELECTRIC ASSOCIATION
S. COUBAN P. MORAN	))	PROVINCIAL GOVERNMENT AGENCIES
C. MARLATT D. ESTRIN	))	NORTH SHORE TRIBAL COUNCIL, UNITED CHIEFS AND COUNCILS OF MANITOULIN, UNION OF ONTARIO INDIANS
D. POCH D. STARKMAN D. ARGUE	)))	COALITION OF ENVIRONMENTAL GROUPS
T. ROCKINGHAM		MINISTRY OF ENERGY
B. KELSEY L. GREENSPOON	))	NORTHWATCH
J. RODGER		AMPCO
M. MATTSON		ENERGY PROBE
A. WAFFLE		ENVIRONMENT CANADA
M. CAMPBELL M. IZZARD	))	ONTARIO PUBLIC HEALTH ASSOCIATON, INTERNATIONAL INSTITUTE OF CONCERN FOR PUBLIC HEALTH
J. PASSMORE G. GRENVILLE-WOOD	))	SESCI

A P P E A R A N C E S
(Cont'd)

D. ROGERS		ONGA
H. POCH	)	CITY OF TORONTO
J. PARKINSON	)	
R. POWER		CITY OF TORONTO, SOUTH BRUCE ECONOMIC CORP.
S. THOMPSON		ONTARIO FEDERATION OF AGRICULTURE
B. BODNER		CONSUMERS GAS
J. MONGER	)	CAC (ONTARIO)
K. ROSENBERG	)	
C. GATES	)	
W. TRIVETT		RON HUNTER
M. KLIPPENSTEIN		POLLUTION PROBE
N. KLEER	)	NAN/TREATY #3/TEME-AUGAMA
J. OLTHUIS	)	ANISHNABAI AND MOOSE RIVER/
J. CASTRILLI	)	JAMES BAY COALITION
T. HILL		TOWN OF NEWCASTLE
M. OMATSU	)	OMAA
B. ALLISON	)	
C. REID	)	
E. LOCKERBY		AECL
C. SPOEL	)	CANADIAN VOICE OF WOMEN
U. FRANKLIN	)	FOR PEACE
B. CARR	)	
F. MACKESY		ON HER OWN BEHALF

INDEX of PROCEEDINGS

L I S T o f E X H I B I T S

---Upon commencing at 10:02 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

MRS. FORMUSA: With Mr. Watson's indulgence again.

We have been discussing the matter of transcript undertakings and a way to facilitate the organization of those untertakings for this panel and future panels. We have a suggestion to make that, perhaps, when witnesses are giving an untertaking, or counsel, that we mention on the transcript the exhibit number that's been assigned, Exhibit 142, and that way, if anyone is doing a computer search, to do a check to make sure we haven't missed one, we can always tickle it with 142.

So, if we are all fairly diligent in saying 142, it will appear on the transcript and there will be no doubt that it is an actual transcript undertaking.

When we then come back to file the answers to those undertakings, we will just assign the suffix of .1 and .2, and that will be noted next to the page in the exhibit file.

THE CHAIRMAN: But there will be no reference to the suffix in the transcript itself?

MRS. FORMUSA: We could do that as well. I counted up over the weekend a number of undertakings and I have a rough idea. We could start doing that.

THE CHAIRMAN: What is your rough idea?

MRS. FORMUSA: About 35.

THE CHAIRMAN: For Panel 2?

MRS. FORMUSA: Yes.

THE CHAIRMAN: So, we start at 40 now.

MRS. FORMUSA: I think I even allowed some grace in the 35 as well. So, I thought if we started at 35 or 36, we could also do it by suffix.

THE CHAIRMAN: That might be easier for searching purposes.

MRS. FORMUSA: It would certainly be one level of assistance for everyone.

THE CHAIRMAN: We will try it and see how it works.

MRS. FORMUSA: Do you wish to start at 142.36?

THE CHAIRMAN: All right.

MR. WATSON: Mr. Chairman, Members of the Committee, I am turning to a new area. As you note, for the last while we were dealing with reserve margin.

With me today I have Mr. Robert Koppe, who is a specialist in power plant.

THE CHAIRMAN: There is a problem with the microphones.

MR. WATSON: As I was saying, Mr. Chairman, today I am turning away from reserve margin issues. I have had with me Mr. Robert Koppe, who specializes in power plant reliability and design, as as well as nuclear safety.

The first area that I will be dealing with is plant life extension issues. I would like to start by introducing the next exhibit, which Mr. Lucas -- and it is a series of excerpts from various documents provided by Hydro.

THE REGISTRAR: That will be No. 144, Mr. Chairman.

THE CHAIRMAN: 144. Thank you.

---EXHIBIT NO. 144: Document excerpts.

MR. WATSON: There are copies up here for the intervenors. You will notice there are three sets dealing with not only the life extension issues, but it looks as though you can also get the environmental issues and the plant performance issues as well. I will be introducing those as exhibits later.

RONALD TABOREK,
DAVID BARRIE,
JOHN KENNETH SNELSON,
JUDITH RYAN; Resumed

CROSS-EXAMINATION BY MR. WATSON (Cont'd):

Q. Panel, before we get into the exhibit, I would like to deal with a little bit of background, if I could.

First of all, some basic definitions, if we could try and get some terminology consistent in dealing with this whole area of life extension.

First of all, plant aging, would a fair definition be: Physical deterioration of equipment which occurs with increasing usage and is beyond matters dealt with by routine maintenance?

MR. TABOREK: A. It can also, if use is also defined to include the period in which the plant is not actually operating but is deteriorating due to time alone.

Q. Second of all, plant obsolescence, the process of a plant losing its economic usefulness, it usually involves some combination of increased expenses due to aging, increased fuel costs, cheaper alternatives, changes in externalities, such as environmental regulations?

A. In my mind, I would exclude the first.

Q. That's the increased expenses due to aging?

A. Due to aging, yes, because that is amenable to maintenance. I think, in saying that, I may be adding a modification to your first definition, that it is over and above maintenance, because aging to me is a phenomenon that occurs; it's not an incremental maintenance that occurs.

Q. So, when you are talking about the increased expenses due to aging not being included with the obsolescence, you, in fact, are moving that concept to what I would define as plant aging?

A. Yes. There is aging and there is maintenance, and the performance of an aged plant depends on how much maintenance you give it. And then the latter two, fuel, the cost of fuel, and the availabilty of new technology, it is economic obsolescence.

Q. Yes. Plant rehabilitation, the non-routine replacement or repair of major equipment and the replacement of obsolete parts such as instruments?

A. To maintain the existing life, to ensure meeting the existing life.

Q. You would add those words to the end of that?

A. Yes. ...

[10:10 a.m.] Q. And last, plant life extension, continued operation of a plant beyond the nominal design or planning life?

A. I would delete the word "design" life beyond the nominal planning life.

Q. In dealing with the DSP, I understand that the plant lifetime that has been assumed is a 40-year plant life for all nuclear and fossil steam units; is that correct?

A. Yes.

Q. Okay. Now, dealing with the background of some of these plants in general, I take it, it is fair to say that the Lambton and Lakeview plants are roughly 20 to 30 years old and are the oldest of the large operating fossil plants?

A. Yes. Lakeview is the oldest and Lambton is next.

Q. And over the past several years, they have shown considerable aging and Hydro is in the process of rehabilitating them, and that rehabilitation program is expected to improve their performance?

A. Yes.

Q. And is it fair to say that these units are not today obsolete, which means that in Hydro's estimation, the rehabilitation program now is

economical?

A. Yes, with some reservations about Lakeview.

Q. Well, perhaps we could deal with that. In dealing with the reservations about Lakeview and the whole economics of obsolescence, if you will, is it fair to say that, just generally, before we get into that, if you need a unit with the characteristics of an existing unit, then you have a very simple decision; you either keep what you have or you bring in a new one.

And if the existing unit --

A. You mean exactly like the old one?

Q. Well, I imagine, in the real world, you are not going to bring in one exactly like the old one. You are going to look at the trade-offs that are going to be available with, I imagine, issues such as new technology, would you not?

A. Yes. If you use a new one in the broadest sense of a new alternative--

Q. Yes.

A. --then, yes.

Q. And then in making that decision, you decide if the existing unit is more expensive than the new unit; then, it, in effect, is obsolete and if not,

then you do the necessary rehabilitation and you keep the old plant?

A. Yes.

Q. And as you were mentioning about Lakeview, I imagine a number of factors you would look at would be things such as the start-up of Darlington, the economic realities that we are experiencing lately, acid gas limits, the fact that Lakeview is not getting scrubbers; all of those issues would be lumped together to determine, in fact, whether Lakeview would or would not be in the mix; is that fair?

A. Yes.

Q. Okay. Now, looking at this in a little more detail, is it fair to say that the economics would primarily involve these four main issues: Environmental issues; capital; OM&A, and that would be operating, maintenance and administration expenses; and fuel?

Are those the four main areas you would look at in making that sort of decision?

A. Yes. They are certainly factors and I am just reluctant to give a blanket exclusion of everything else, though.

Q. Well, no. I wasn't trying to --

A. Yes. But those are certainly four

prime factors, important factors, in the decision, yes.

Q. Okay. Is there one that I have omitted that would be more important than any of these?

A. Well, fuel supply, for instance, comes to -- oh, you have fuel. I'm sorry.

Q. Okay. I thought I --

A. Yes. You did include fuel.

The availability of alternatives, and if you are applying those same factors, but it is seldom that four factors alone influence everything about a decision.

Q. It is fair to say that those are four main factors?

A. Yes.

Q. Now, dealing first with the environmental factor, if we could, is it fair to say that if we put the same or similar emission control equipment on an existing unit as would be on a new unit, then the units are environmentally very similar with respect to the emissions?

A. Not, not necessarily. There may be, say, space considerations that would prevent putting the same control device on an old unit as a new unit. There may be problems with the delivery of raw materials and the extraction of wastes. There may be

factors in the operation of the old unit that do not permit a perfect mating, the same degree of mating that you can get with a new unit.

Q. And I suppose it is also fair to say that in a new plant, you would have environmental concerns, such as new site might be required, there might be new transmission required, there might be more construction dust; things like that.

Is it fair to say in looking at this as just a first order approximation, if you will, that the new units and the old units, taking into account some of the factors you mentioned, would be environmentally similar with respect to their emissions?

A. I think that is a long jump to make. I do not think I would agree to that--

Q. Okay.

A. --for the reasons I have outlined. In many instances they can be, but I don't think you can give a blanket assurance.

Q. One of the factors you mentioned was lack of space. You were probably referring to Lakeview, were you?

A. Yes.

Q. I have come across that in the literature. I haven't come across that for any of the

other plants. Is it fair to say Lakeview is the only plant where that is an issue today?

A. Yes.

Q. So, in another plant - say, Lambton, for instance - if that issue didn't occur, and if you were able to get sufficient supplies to Lambton, then based on what you have said, you would probably have a situation where there would be similar emissions from a plant, such as Lambton, which had backfitted environmental controls on it, as opposed to a new unit?

A. Now. You are using environmental controls in their broadest sense there--

Q. Yes.

A. --I am answering you to this point primarily with respect to scrubbers, because you have a host of environmental controls which depend on the future regulations that you will be forced to meet, and so one of the next set of controls that is possible is selective catalytic reduction.

And then going beyond that, environmental regulations in the past have been tightened - our coal plants - approximately every two years, and there remains a heightened environmental sensitivity, so I am very reluctant to -- and what I mean by that is, I expect further changes in the future. I don't exactly

know what they will be.

Having said that, I am not in a position, then, to say that, in future, there will be space for whatever new environmental devices are required on our plants over the next 20 years.

MR. SNELSON: A. I think it's fair to say that as a principle, that it is more difficult to add facilities to an existing design than it is to incorporate them into the design from the initial stages of the design. That, I think, is the principle that makes it more difficult to add things to the old plant than to incorporate them into the new.

Q. Have you investigated adding SCRs to Lambton or Nanticoke?

MR. TABOREK: A. No, not in detail.

Q. Okay. Just turn to the Exhibit 144. You will see that what is labelled page 3 is the Hydro response to Interrogatory 2.14.11, and on the second page of that, is the actual answer.

What I would like to deal with is the cost of adding scrubbers and as you see in following down under the heading "Response," No.(a), the cost in current 1989 dollars of scrubbers at Lambton is 181.3 dollars per kilowatt.

A. Yes. ...

[10:22 a.m.] Q. Could I ask you whether that includes any allowance for funds during construction? I wasn't able to find anything on that and I made the assumption that it did not. But can you help me as to whether it does?

A. No, I can't.

Q. Mr. Taborek, if you could just get back to me on whether that does or not, I would appreciate that. And pursuant to what Mrs. Formusa --

THE CHAIRMAN: The cost of what? I'm sorry, I didn't quite get that.

MR. WATSON: The cost of funds during construction, the cost of money, in effect.

THE CHAIRMAN: The cost of borrowing money?

MR. WATSON: Yes.

THE CHAIRMAN: The cost of money.

MR. WATSON: The cost of money, indeed.

And as Mrs. Formusa was saying earlier, I assume that would be No. 142.36.

Q. If we continue on with that same exhibit. On page 5, Mr. Taborek, that is an excerpt from the Thermal Cost Review. And as you look in the first column, under part 4 "Improved Estimates, Current Conditions," figure 2.6.1.4, under the heading

"Existing Site, SPC Dollars per Kilowatt," and you follow down to median estimate, the figure is 259.2. Do you have that?

MR. TABOREK: A. Yes.

Q. My understanding is that does not include a cost of money, that figure?

A. It does not appear to.

Q. And in comparing these figures, it seems as though the cost of scrubbers at Lambton would be less than the capital cost of scrubbers for a new 4 by 500 megawatt plant, which is what Lambton is; is that fair?

A. Yes. The comparison is between 275 for the new site and 259 for the old site.

Q. Yes.

A. Existing site, pardon me.

Q. Versus the 181 for Lambton?

A. Yes, as recorded in that interrogatory.

Q. Yes, thank you.

Could you just turn briefly to the issue of SCR. Would the same cost relationship exist with respect to SCR as seems to exist here with respect to scrubbers on old versus new plants?

A. I don't think you can say that. I

think you would actually have to look at it and make estimates and then reply.

Q. Is that because, in fairness to you, Hydro really hasn't had much experience with SCRs?

A. Correct. And we have not prepared the same kind of estimates or gone through the same process with SCRs as we have gone through with scrubbers.

Q. Could you help us out as to why Lambton would be cheaper; why it seems to be roughly $80 per kilowatt cheaper?

A. In this instance, I think you would have to address the questions of the breakout of the two columns in the rationale to a further panel, the panel dealing with fossil.

Q. That would be Panel 8?

A. Yes.

Q. We'll take that up with them, thank you.

If we could turn now to the second factor that we are -- or another factor we are talking about, the OM&A costs. If you turn to the next page in Exhibit 144, that is page 7, which is the answer to Interrogatory 2.9.10, dealing with the OM&A costs for the existing units in the planning period.

Under fossil, you will see that Lambton has a value of $34.4-million in 1989 dollars, and Lambton is a 4 by 500 plant. Nanticoke has a value of $59.9-million in 1989 dollars, as well, and that is an 8 by 500 plant. If you could just make note of those figures, and then turn the page of Exhibit 144.

A. Just a moment, please.

Q. Certainly.

A. I've turned the page, thank you.

Q. If you turn the page, you will see an excerpt from the Thermal Cost Review 2-4-1, "Primary Plant OM&A Direct." And if you look at the second column under item No. 4, "Improved Estimates, Current Conditions," and under the heading "Millions of '89 Dollars Per Year," it says median estimate direct 28.6.

A. Yes.

Q. And if you turn the page to page 9 of Exhibit 144, if you look at almost the same place on that page, which is dealing with indirect OM&A costs, you will see that the figure there is $2.5-million in '89 dollars.

Now, I have added those, the two figures from the Thermal Cost Review, together and get $31.1-million in '89 dollars. And I have looked at the results of Interrogatory 2.9.10, and it appears as

though the OM&A costs for a new plant are roughly the same as for an existing plant. They are somewhat smaller than Lambton, and it looks as though they may be a little larger than Nanticoke, taking into account the fact that Nanticoke is twice as large. So, is it fair to say that the OM&A costs are roughly the same?

A. Yes.

Q. I would like to turn now to the fuel costs. And again, dealing with a new plant versus one of the existing plants, assuming the same environmental constraints and assuming they burn the same fuel, is it fair to say that the heat rates should be essentially the same for the existing units and those that you might construct in the future? And if that is so, then, in effect, would not fuel costs be essentially the same?

A. Excuse me a minute, I would like to consult.

Q. Certainly.

---Off the record discussion.

MR. TABOREK: Yes, the heat rates would be about the same, if you replace with in kind.

MR. WATSON: Q. I'm sorry, I didn't --

MR. TABOREK: A. If you replace with "in kind," the same type of generation.

Q. And as a result of that, the fuel costs would be essentially the same?

A. Yes.

Q. If we could turn now to capital costs.

A. Replace in what time period?

Q. During the life of the plant.

A. During the life, okay.

Q. Yes.

...

[10:37 a.m.] Just dealing with that comment for a minute, Mr. Taborek, I guess I don't understand why it would make a difference if the heat rate was the same, if they are burning the same fuel, why would it make a difference as to when this occurred?

A. Well, with heat rate, if you are talking about replacing these plants when they meet the end of their life 20 years from now, compared to replacing them now, the conditions can be significantly different. You are using, on the one hand, information about Lakeview and Lambton say as they are now; you are not using information about what state they are going to be in 20 years from now, and that's where I have the trouble.

Now, with heat rate, there is perhaps another decade in which new technology may change, but I think, maybe, for an identical plant, it may not be too much different. But I would think the OM&A costs and other costs could be markedly different for a future Lambton or a future Lakeview than the ones we are reporting here.

These were prepared with respect to their operation over the remainder of their existing life, not an extended life.

Q. And how would life extension make

these figures change?

A. Well, that's the whole question, that you don't know. You cannot now meaningfully project what those will be. And as I gave in my direct testimony, the prudent way to do this, if you make a judgment now, you gamble. You gamble everything on a forecast and forecasts are not that reliable. So, it's not a prudent thing to do.

The prudent thing to do is to make this judgment at a future time when enough of the world has evolved that you know what its maintenance and other costs are, you know what kind of environmental regulations have to be applied, you know what the prices relevant to that fuel are at that future date, and that could be different. And at that point you are able to make a decision.

It is very risky to make a life extension decision now because we have already, we believe, extended the life of these plants to the maximum prudent feasible limit.

Q. Now, if we could turn to capital costs, Mr. Taborek. If you look at the next interrogatory in the package, which is Interrogatory No. 2.9.11, on page 13. I believe that table shows the capital costs of Lambton in dollars per kilowatt as

331.

A. Yes.

Q. And if you add the figure for scrubbers, that we saw earlier, of $181, that would give you a total of $512, if my mathematics is correct?

A. Yes.

Q. Now, if we could turn to page 15 of Exhibit 144 - again, an excerpt from the thermal cost review - talking about the capital estimate for a 4 by 500 plant, you can see in the second column, the third line under paragraph No. 2, capital cost is said to be $1,391.2 per kilowatt. If you turn over the page of the same exhibit, you have a graph showing the two figures comparing Lambton capital costs, in dollars per kilowatt, with a new plant, in dollars per kilowatt, and they are similar, 4 by 500 plants.

And you will note, just as an aside, I had refurbishment there and I crossed that out. I am talking about rehabilitation versus new construction.

Now, it seems to me, in looking at that graph, that we have a substantial difference in costs between rehabilitation and new construction; is that fair?

A. Yes.

Q. Is it also fair to say that -- again,

I didn't see a line for this when I was looking at the costs, but it appeared to me that there was no cost of money involved in the figure of 1391 for the new plant.

A. I am not familiar with the details of the thermal cost review. I think Panel 8 again would be the panel to direct that to.

Q. I was simply referring to Column 1 of page 15 of that exhibit.

A. Yes.

Q. And while it had figures for construction, permanent materials, engineering, overheads, contingency--

A. That's correct. There is no interest there.

Q. --it appeared not to have an interest figure. And if, in fact, the Lambton figure did have a cost of money, that would make that comparison even more favourable, would it not?

A. Yes.

Q. And in looking at rehabilitation or life-extending a new plant, is it fair to say that when you put parts in it today, often the parts that are put in would be much better and would last longer than the parts that were originally in there? If effect, you are getting the benefit of new technology today?

A. No, I don't think I would agree to that. In some instances, it may be true, and in some instances, not.

Q. So I can't make a generalization, but in looking at individual plants, we may find benefits like that?

A. I think you are making a statement that I can't give any evidence to support.

MR. WATSON: Thank you.

Mr. Chairman, I should say as I am going along, that I did have the benefit of meeting with Mrs. Formusa and some of the Hydro staff on Friday afternoon for a considerable period of time, and as a result of that, I think I have been able to focus some of these questions. And hopefully, we should be able to deal with them in a quicker fashion and be more efficient with what this panel can handle.

Q. Panel, if we could now talk about a technical issue, in a very general sense, and please let me know if you don't think you are competent to deal with this.

Let me give you a hypothetical question: You have three identical units. Unit A is mothballed, and by that I mean it is shut down with the equipment properly laid up. Unit B is operated flat out, by that

I mean it's operating at full power except for occasional outages.

MR. TABOREK: A. Base load operation, is what you are referring to?

Q. Yes, that's precisely it, base load operation.

And Unit C is operated with daily cycling, daily start-up and shutdown.

Which unit would you expect to be in better physical condition at the end of 40 years?

A. There are so many parameters affecting the condition of a unit at any point in time that I don't know how could you answer that question. I mean, one could take talk at great length on factors, but to give you an evidential answer, I think is a very hypothetical question.

Q. Well, is it fair to say that laying up a unit, or mothballing a unit, is less stressful and would cause less physical deterioration than running it flat out or cycling it?

A. Are these all identical units?

Q. Yes, they are all identical units.

Is that a fair statement?

MR. SNELSON: A. Yes. But there are other factors which will come into play. An operating

unit will continuously have upgrades and improvements made to it through normal maintenance and rehabilitation procedures. The unit that is laid up for a long time will not receive the benefit of those.

MR. TABOREK: A. Plus a unit that's been mothballed will have been cycling intensively just before it's been mothballed, because it would have been a marginal unit.

Q. And cycling is more difficult on a unit than base loading it?

A. Again, all other things being equal - and that is not necessarily the case - then, yes.

Q. So, subject to the comments that Mr. Snelson has made and you have made, it appears as though there is a little bit of a hierarchy emerging from this, that --

A. I think you are pushing our comments too far. Our comments are that we really don't want to attempt an answer to that. It is a far more complex thing to describe than merely listing one parameter for each of the plants and saying which is best. It's much more complex than that.

Q. Would Panel 8 be able to provide me more assistance with this scenario?

A. Well, I think they would have the

same difficulty. I know we frequently go to the engineering people and ask questions, and we would ask our questions in a much more detailed fashion than this. I think they want to know operating histories and conditions and future use, et cetera.

Q. Okay. Well, if we could turn back to Interrogatory 2.9.11, which you will find at pages 10, 11, through to 14 of Exhibit 144. You will see the interrogatory has two attachments to it. The first one, on page 11, is called the Lakeview Condition Assessment Finding Summary, and the one on page 12 is the Lambton Condition Assessment Summary. If we could just deal with the Lakeview condition assessment.

Just before we go through this, this is a list of the major equipment deficiencies that were found in Lakeview when it was recently assessed; is that fair?

A. Yes.

Q. Now, if we look at the boilers, the first item there is re heater tubing on units 3 to 8, overheating damage. Is it fair to say that that type of deficiency would only occur on a unit that was either cycling or base loading; it wouldn't occur on a mothballed unit?

A. I think I can give you one step based

on logic and then I would have to pass you on to the Panel 8 for the details.

If the unit is not operating, it's unlikely to get over overheated.

Q. Right, that was my point. And as a result, it wouldn't experience this overheating damage?

A. That's right. But you have to now ask questions about the performance of that unit in the time before it was mothballed, at such a time when it was probably operating in a peaking mode.

Q. Yes.

THE CHAIRMAN: Well, a mothballed plant could have this kind of damage.

MR. TABOREK: It could have acquired this kind of damage in its earlier life, yes.

MR. WATSON: Q. But there is no way that mothballing it is going to make this worse and there is no way that, while it's mothballed, it is going to have this sort of damage occurring; is that fair?

MR. TABOREK: A. That's correct.

I did make a caveat to your initial definition of aging in which I identified certain wear that occurs strictly as a function of age, regardless of whether it is operating or not. ...

[10:45 a.m] A unit that is mothballed -- while mothballing is not necessarily perfect, and it is not necessarily receiving the maintenance, as Ken said, that other operating units may have. Therefore, as you see, I am very reluctant to give any sort of blanket assurances, just based on one parameter for each of these types of units.

Q. And I certainly wasn't meaning to imply that while the unit is mothballed, it wouldn't suffer any deterioration. The only point I was trying to make was that there would be significant -- or there would be deterioration with a unit that was running, as opposed to a unit that wasn't running?

A. There would be different types of deterioration.

Q. That is correct. They would be different, and in looking at the differences in those deteriorations, the deterioration that occurs in an operating unit is going to be more costly than the deterioration which occurs in a mothballed unit?

A. Well, you used the definition of "aging," which was over and above maintenance, and I came back with a definition that there is aging and there is maintenance, and that the performance and the condition of the unit depends on both its age in

operation and the amount of maintenance it has received. And if it is operating, it would receive additional maintenance.

Q. Well, I guess there are two answers to that, Mr. Taborek: One, you can certainly maintain a mothballed unit; and, two, this is the Lakeview assessment as of today--

A. Yes.

Q. --and it has been receiving some maintenance over the years.

A. Yes.

Q. And it is still in this situation, and Lakeview is -- I am not sure exactly what your evidence was, but you indicated some hesitation when we were talking about the economic obsolescence of Lakeview.

A. Yes. You are aware that our cost estimates for rehabilitating Lakeview have increased--

Q. Yes.

A. --over recent time, indicating again the difficulty in forecasting how much maintenance a unit requires because it has changed sharply over a few years.

And again, you are, in effect, asking me to make condition statements on simple parameters, when

very detailed assessments of stations have difficulty in producing accurate, for the type of analysis you appear to be leading to.

Q. If you could look just briefly at Attachment 1, "The Lakeview Condition Assessment," can you point out any of the factors, under either boilers, turbines, generators or unit controls, that would result while a unit was mothballed?

A. I think that I am not an engineer familiar with the detailed condition of stations and I think you should refer that to Panel 8.

Q. Okay. Thank you.

A. Looking down the line, Unit Controls.

Q. Well, based on your answer about Panel 8, I am not sure I want to get into that with you. I would be pleased to if you want to discuss it more.

A. No.

Q. But in fairness to you --

A. I would agree. Panel 8 are the authorities.

Q. Yes. If you could help me with just one thing you said in your evidence, before we move on.

I understand the original estimate for Lakeview, I believe, was just over $1-billion, and I

think the estimate for Lambton was just over 600-million.

In your evidence, you mentioned a figure of $2.4-billion.

A. Yes.

Q. And that was for both of them?

A. Plus two scrubbers.

Q. Plus two scrubbers.

A. Yes. And if I may correct you, the original estimate for Lakeview was less than 1-billion. 1-billion was approximately the committed number and there were much lower estimates before that. As they went through the inspection program on the station, the number was revised before it was committed.

Q. Thank you. So, the current figure, the figure as of today, is $2.4-billion, which includes the rehab and scrubbers?

A. Yes. It includes Lakeview rehab, Lambton rehab, and two scrubbers at Lambton.

Q. Yes. Thank you. I assume from your answers that costs have gone up since commitment of rehab; is that correct?

A. That is correct.

Q. And is that a result of your continuing assessment of the units, and in effect,

discovering more wrong with them than you originally thought?

A. Again, I would refer you to Panel 8 for a detailed condition report on Lakeview.

Q. Do you have any information on why costs have gone up since commitment?

A. I believe it is many factors and I am not an expert in those factors.

Q. I am not asking for an explanation of the factors. Could you just tell me what the factors are, so I know what to probe with Panel 8; to the best of your knowledge, what those factors are?

A. Excuse me just a moment, please.

Q. Sure.

MR. SNELSON: A. I don't think we can help you very much. I mean, clearly, you can divide them into two factors, but for the ratio between them, I don't think we can help you.

The two factors would be that new things are found that require fixing and that the cost of fixing the things that you have found is more expensive than you thought.

And the difficulties of working around existing equipment in an existing station make cost estimating for rehabilitation a particularly difficult

exercise. But I think, beyond that, we cannot help you, but Panel 8 probably can.

Q. Just a quick question on clarification. The $2.4-billion; that is the cost today or is that the committed cost?

MR. TABOREK: A. That is the present money allocated for those programs and that is what we expect it to cost.

MR. WATSON: Mr. Chairman, I had a further series of questions dealing with plant conditions and the prospects for economic life extension of those plants, as well as questions on the conversion of Lennox to another fuel.

Based on what I have heard the panel say this morning and, also, more importantly, my discussions with Mrs. Formusa and her staff on Friday, I will be deferring those questions to Panel 8.

THE CHAIRMAN: All right.

MR. WATSON: Mr. Chairman, that deals with the area of plant life extension to the extent that I can deal with it during this panel.

The next major area I would like to turn to is that of environmental concerns, and Mr. Logan has another package of documents.

THE CHAIRMAN: Mr. Lucas, I suggest, for

the purpose of the record.

MR. WATSON: Mr. Lucas. I'm sorry. My apologies, Mr. Lucas.

THE CHAIRMAN: Mr. Logan was here Friday; he's your colleague. (Laughter)

MR. WATSON: That's right.

THE CHAIRMAN: Do we have an new exhibit?

MR. WATSON: We do.

THE REGISTRAR: 145, Mr.Chairman.

THE CHAIRMAN: Thank you. Can we have it?

---EXHIBIT NO. 145: Environment reference material to be used in M.E.A. Panel 2 cross-examination.

MR. WATSON: And again, for the intervenors, there is a similar package available at the front desk.

Q. Panel, as I indicated, we will be turning to environmental concerns. Perhaps now, Ms. Ryan, you and I can have some question and answers.

The first thing I would like to do is look at the general topic of current emissions versus current regulations.

MS. RYAN: A. Okay.

Q. And if you turn to the first graph in Exhibit 145, you will see a figure of, dealing with

1989 emissions as a per cent of allowable emissions.

It appears to show that radioactivity is less than 1 per cent of the allowable emissions; whereas, the SOx and NOx combination is a very high percentage, about 83 per cent of current emissions.

Does that accord with your understanding of the situation?

A. That's correct.

Q. Still looking at that graph, Ms. Ryan, could you help us with where the actual emissions and limits on emissions for particulates and other major pollutants would fit into this type of graph?

And just generally, would they be closer to the left of radioactivity; that is, very small in comparison to allowable emissions, or very high? Let's deal first with pollutants.

A. Pollutants?

Q. Or particulates. I'm sorry.

A. I believe, one of the graphs, the next graph that you have, gives a plot for particulates. I think what you have to appreciate is that for radioactive emissions from nuclear stations, and for acid gas emissions from fossil stations, we have emission caps, an acceptable amount that can be emitted.

For a lot of the other emissions, it is an emission rate based on design, and so, during the design of the station, we are licensed based on a calculation of what our emissions will be and what the resultant groundlevel concentration might be, and then there are ambient criteria which are to be met.

Q. Okay.

A. But those ambient criteria include all industry.

Q. Thank you. And in Graph 1, we have indicated a per cent of allowable emissions. Are there any other emissions where there are current caps or standards which we could fit into that type of graph, as opposed to dealing with them on an ambient level?

A. Again, as I mentioned in my direct evidence, we have opacity limits which are measured at stack, and that is a limit.

Q. Okay.

A. Thermal emissions to water have temperature emission limits.

...

[11:00 a.m.] Q. And where are you in meeting those limits? Where would you be on this graph? Are you pushing the envelope or do you have very safe margin on those, where there are limits?

A. It varies, depending on station operation to plot it this way, but generally, we meet the opacity limit 97/98 per cent of our operating time; and for thermal emission limits across all stations, we would meet the limit 99 plus per cent of the time.

Q. And that is a bit different from what this graph is saying though, isn't it?

A. Yes.

Q. That is a bit like apples and oranges, because when you are looking at the SOx and NOx here, you are probably meeting them most of time, as well, but it doesn't give the same idea, does it?

A. No. And I don't, right here, have the information to plot it in the same way you have these plotted.

Q. Ms. Ryan, if you could turn just a bit out of order to page 9, Exhibit 145, you will see about three-quarters of the way down the page, and this is page 10 of the State of the Environment Report for 1989, there is a paragraph that starts "Any initiatives to reduce NOx levels..." Do you have that?

A. Yes.

Q. And it goes on to say that three fossil fuel generating stations, Nanticoke, Lakeview and Lennox, currently exceed Canada's existing emissions standards (258 nanograms per joule) as NO(2) for coal and 129 nanograms per joule as NO(2) for oil for NOx.

Is it fair to say that these standards were adopted after those units were built?

A. Yes, that's correct.

Q. However, they are currently operating with emissions which are above those a new unit would have to meet?

A. Yes. Though for our stations, we are generally governed by provincial regulations and so we would have to meet provincial requirements which these stations do.

Q. And I understand that Nanticoke already has low NOx burners; is that correct?

A. That's correct.

Q. And in fairness, that would lower the NOx emissions by about 30 per cent?

A. Around 25 to 30 per cent.

Q. Do you have any idea of what the emissions are from Nanticoke, after the low NOx burners

have been installed? Are they still above the 258 nanogram per joule limit?

A. Yes, they are.

Q. Do you have any idea of, just roughly, where they are above the limit? Are they close?

A. They would still be above the limit. I don't have the exact numbers with me.

Q. If you don't know, just tell me. I don't want to push you.

A. I don't know the numbers off the top of my head.

Q. Could you tell me whether they are close?

MR. TABOREK: A. No, they are --

If I may?

MS. RYAN: A. Sure, go ahead.

MR. TABOREK: A. You would need selective catalytic reduction on a number of units to meet this regulation. This one, I think, Judy is --

MS. RYAN: A. No, this is the existing federal limit and--

MR. TABOREK: A. Oh, the existing, okay.

MS. RYAN: A. --it isn't as stringent.

But I don't know our emissions in

nanograms per joule, I know them in parts per million, and they are running about 450 parts per million, but I can't do the conversion for you right here.

Q. I think we will have to take that. I am not equipped to make that conversion either.

Ms. Ryan, if you could turn to figure 2, which is the percentage of allowable ambient concentrations. First of all, these figures, as indicated, were taken from the 1989 State of the Environment Report and the Stack Emissions Testing at Lakeview, Interrogatories 2.15.7 and 2.14.70.

Now in looking at those figures, they seem to indicate a very high allowable ambient concentration for SOx, NOx, particulates, and a very low concentration for radioactivity. Is that the current reality?

A. It's the current reality. I think there are a couple of things you need to recognize here. These numbers were obtained by taking stack gas emissions as measured, and going through a model calculation to see what the impingement concentration would be in the environment, based on our measured stack emissions. And the model looks at worst-case meteorology in that range, so these are correct, based on the model. But they don't represent what our

emissions would look like in the environment on average.

Q. And is it also fair to say that the radioactivity is a worst-case number?

A. You are comparing different things, because for our nuclear stations, we have emission limits and so we measure our emissions against a limit. And they were specified at the time the station was designed, so technology was available and affordable and the stations were designed to meet that level.

Our fossil stations were designed to meet the laws at the time, but the emissions that you see here were not recognized as being the environmental concern that they are today.

Q. Well, that's certainly correct, Ms. Ryan. I don't mean to be unfair, and we could go a step further and point out that, in looking at SOx, the use of scrubbers could reduce that figure by as much as a factor of, maybe, 8, 9 or 10. Is that fair?

A. That's correct.

Q. Which would bring the figure down to, maybe, somewhere between 8 and 10 per cent?

A. Yes.

Q. And also, low NOx burners could reduce the NOx emissions, as you said, by 25 to 30 per

cent?

A. Yes. If you take into account, though, that the regulation is also stepping down, our NOx acid gas and S0(2) emissions are always going to be a fairly high percentage of regulation in the foreseeable future.

Q. Which is what we are showing on figure 1 of this same exhibit?

A. Yes.

Q. And you don't anticipate the same situation will occur with respect to the nuclear plants?

A. We expect that the allowable emission limits will be reduced in the next few years, but we don't know what they will be reduced to, so our emissions as a percentage of regulatory limit may go up, even though our emissions are not going up.

Q. And also dealing with NOx, again, just to be fair to you, the use of SCR would probably reduce the NOx emissions by another factor of 4?

A. SCR could reduce NOx emissions in the ballpark of 80 per cent.

Q. And also, looking at the particulates, if you repaired the precipitators at Lakeview, that would reduce certainly the particulates

and maybe some of the other pollutants; is that fair?

A. That's correct.

Q. Do you have any idea of what sort of factor that would reduce the particulates by, if the precipitators were corrected?

A. Again, it would depend on the design efficiency of the precipitators. If you can select various efficiencies, depending on what type of precipitators you put in. So I can't give you an answer, but, certainly, the particulate would be reduced.

Q. Do you know what the design efficiency is of the existing precipitators?

A. No. Again, that's something that the Panel 8 people would have the specific numbers.

Q. We will deal with that then, thank you.

So, Ms. Ryan, in going through some of the improvements that I have made by discussing scrubbers, low NOx burners, SCRs, precipitator adjustments, things like that, we would be able to reduce the figures in graph 2, but we would still have a situation - even if we could snap our fingers and have this all done today - we would still have a situation where SOx, NOx, particulates, would be in the

order of 8 to 10 per cent or more, versus, shall we say, radioactivity, which would be less than 1 per cent as of today?

A. Yes.

Q. Ms. Ryan, we have been looking at some of the current realities. If I could turn now to some future environmental limits and their impact on the current system.

Now, I understand from looking at an OEB interrogatory, that part of the mandate of Hydro's environmental decision is to attempt to anticipate changes in future environmental regulations and their impact on Hydro's operations. Is that fair?

A. Yes.

Q. And I understand that there have been a number of proposals to decrease allowable emissions from fossil-powered plants. Examples include the NOx protocol, CO(2) emissions reductions, solid waste initiatives, VOCs, particulates, to just quote some of them. And I assume you are familiar with all of those?

A. Yes.

Q. Now what I would like to do is look at some of these new emission limits which have been proposed and see what effects they would have on the operation of Hydro's existing fossil units.

And this is of particular interest if we are trying to find out what would happen if Hydro were going to meet load with more of its existing fossil units; that is, if they were going to life-extend them and base load them. And in looking at this, what I would ask you to do, in effect, is look at case 26, which is, in effect, the fossil option, if you will. It, as I understand, does not have any nuclear in it. And if we could just adopt that as a bit of a surrogate for looking at this scenario, I think that might be of some assistance.

If we could turn first to carbon dioxide emissions. I understand that right now there are no limits on carbon dioxide emissions by Hydro; is that correct?

A. That's correct.

Q. And I understand that there has been a lot of concern about carbon dioxide emissions and, in fact, there have been several regulatory groups which have proposed a 20 per cent reduction in CO(2) emissions by the year 2005, and 50 per cent reduction by 2020; is that correct?

A. Yes. But it is also fair to say that there has been great concern at whether Ontario or Canada could meet those limits. And there has been a

lot of discussion whether we are looking at reductions or stabilizing by the year 2000.

Q. When you say stablizing, just staying at the current level?

A. Yes.

Q. And the current level for what year.

A. I believe it is, I am not sure, '88, '89.

Q. And in fairness, I assume that part of the difficulty is because, as I understand it, there is no technology currently available to deal with CO(2)?

A. That's right. There is no scrubber technology that would be cost effective, as there is for NOx or SO(2).

...

[11:15 a.m.] Q. If you turn to page 5 of Exhibit 145, you will see a graph entitled at "Atmospheric Emissions CO(2) for the Medium Load Forecast." This is your graph taken from page 5.37 of the environmental analysis. And of course, as goes without saying, if there is any difficulty with this graph, I am sure you will let me know, but I hope it's an accurate representation of that graph.

I notice that you have page 5.37 in front of you, so I assume that the graph is accurate.

A. Yes, it's fine.

Q. In looking at this, you can see that case 26 is plotted assuming medium load growth, and by the year 2014, the CO(2) emissions are roughly two-and-a-half times the proposed 20 per cent limit; is that fair?

A. Yes.

Q. And I suppose it's also fair to say, in looking at the graph that's there, that the CO(2) emissions would continue increasing beyond the year 2014, based on what we know about the components of Case 26; it is a fossil option.

MR. SNELSON: A. Well, you started your questions saying this was a surrogate for increased operation of the existing system.

Q. Yes.

A. And to some degree your premise may be correct. But ultimately, it has to break down, because there is only a certain amount of existing coal-fired plant in the existing system. And if you run it flat out to 24 hours a day, there is only so much coal it can burn and so much CO(2) it can produce. So, eventually, this runs out of capability of supplying the energy that's demanded and then the CO(2) projection becomes meaningless.

Q. Yes. Then it would decrease at some time.

A. Your premise was life extension of existing facilities, I believe.

Q. Yes.

A. And presuming indefinite life extension, if that were feasible, then it would eventually, from existing facilities, stabilize. But you still have the question as to where would the additional energy be generated that's demanded, that is not answered.

Q. Yes, I understand that. And just to put it in numbers so that I am not misrepresenting the situation. I understand that, according to the plan, Hydro plans on retiring about 6.7 gigawatts of coal

production during the 25-year planning horizon, and in Case 26, they are planning on building 7.4 gigawatts of new base load coal.

So, on the assumption that we were life-extending the coal plants, there is a reasonable approximation there, that while it isn't one-to-one, it is close, within .7 of a gigawatt. But I certainly take your point that, past 2014, this isn't going to continue forever, simply because -- well, I don't need to repeat what you said.

Q. Now, also, page 5 deals with the Case 15, and, again, from the same reference, it produces the graph for Case 15. You note that, by the year 2005, even Case 15, which has a nuclear component, as well as a fossil component, involves just barely meeting the proposed limit, although it does decrease as the nuclear units come on line later in the case, later in the planning life. That's my understanding of that; is that fair?

MS. RYAN: A. Yes.

MR. SNELSON: A. You referred to it as a proposed limit. Its status in the DSP is an illustrative target. Now, that may seem like a fine line, but it was the terminology, illustrative target, was taken from a document produced by the federal and

provincial Ministers of Energy, and I believe it's somewhat different and perhaps not quite so definitive as a proposed limit.

DR. CONNELL: That is, however, the language used in the original figure, 5.18.

MR. SNELSON: I believe that we misspoke ourselves, if you like, and the main document refers to it as illustrative target. So, yes, you are correct. We have used two different terminologies.

MR. WATSON: Q. Is it fair to say, in looking at Case 15, that if, in fact, you did life-extend a large number of your coal plants, which is currently not the plan for Case 15, that you would not be achieving either the illustrative target or the proposed limit of 20 per cent?

MR. SNELSON: A. That would depend upon how they were used.

Q. Well, certainly, if they were used in base load, you wouldn't achieve it; is that fair?

A. If they were used in base load, we would not achieve it.

Q. And then we would get to intermediate load, and that, of course, is going to be a function of how often they are run and what capability factors; is that fair?

A. What capacity factors, yes.

Q. What capacity factors.

And in looking at Case 15, there appears to be, if you will, a blip in the years 2001 to 2004, followed by a decrease in CO(2) emissions. Is it fair to say, in looking at that blip, that, first of all, Case 15 involves building no new coal plants?

A. Case 15 doesn't build new coal plants, that's correct.

Q. That blip in CO(2) emissions would be due to increased usage of existing fossil units during that time, and possibly even increased use of some combustion turbines?

A. Yes.

Q. And all of this results -- sorry, before I get to that. And this increase results from continued load growth, combined with a long lead time, to bring on the new nuclear plant in Case 15?

A. Yes, but somewhat offset by demand management, Manitoba purchase, hydraulic purchases, et cetera.

Q. And I would like to get into some of those items in a few minutes, purchases and things like that.

So, just finishing up with Case 15. If,

in fact, the nuclear approval for Case 15 is delayed, that would make it more difficult for Case 15 to meet the CO(2) target; is that fair?

A. Yes.

Q. Now, in fairness, I suppose you could also say that it might be possible to achieve a CO(2) reduction without building nuclear, if you burned enough natural gas; is that fair?

A. You can substitute natural gas for coal. If you were to do that, then you approximately halve the CO(2) emissions per unit of energy produced, per unit of energy changed from coal to natural gas.

Q. And another trade-off would be that the cost would be very high?

A. Yes.

Q. And as you were mentioning a few minutes ago, another way to deal with this would be to, in effect, purchase power, to deal with the CO(2) limit?

A. Yes.

Q. And just before we get into that, I assume that the philosophy of CO(2) targets, or limits, is to produce reduction in world-wide emissions of CO(2); is that a fair statement?

A. I would presume that that is the -- I

don't presume it. That is the motivation that I understand behind CO(2) limits.

Q. And that, of course, is why we have inter-provincial, federal, international conferences and discussions dealing with this issue?

A. Yes.

Q. And it's also fair to say that reducing emissions from just one area, or just one industry, and simply substituting emissions from another area is not in keeping with this philosophy and laudable objective it's trying to achieve?

A. I'm sorry, I missed the question. Can you repeat it?

Q. Is it fair to say that reducing emissions in one area and substituting them with emissions in another area is not meeting that objective or that philosophy?

A. If the emissions in the other area are equal or higher, then that is correct.

Q. Now, it's certainly trite that Hydro could just simply reduce the use of their only fossil units and purchase more fossil power from another source, and while this would reduce Hydro's CO(2) emissions, it's not going to achieve this more global purpose of dealing with the total amount of CO(2)

emissions. I assume that's a fair statement.

A. I believe that is true, assuming that the purchased power would have equivalent CO(2) emissions or higher.

Q. Therefore, it seems to me, in assessing Hydro's ability to meet a target or a limit on CO(2) reductions, it's more realistic to consider all sources of power provided by Hydro, whether internally generated or externally generated. And in saying that, I would like to talk about the recent past at Hydro. I understand that Hydro has made significant purchases of power from the U.S. in order to stay within certain limits, emissions limits; is that correct?

MR. BARRIE: A. You're moving away from CO(2) now, into acid gas?

Q. Well, now that you mention it, let's deal with acid gas.

A. We haven't made any purchases to respect CO(2).

Q. But in making purchases to deal with acid gas, you would also be dealing with CO(2) just as necessary bi-product, would you not?

A. It would influence CO(2) as well, yes. Any time you reduce fossil production, you will

affect CO(2), yes. But that wasn't the purpose of the purchase.

Q. So, the purpose of the purchase was to reduce acid gas?

A. It was, yes.

Q. Well, while the purpose was to reduce acid gas, I guess it's fair to say that you did also achieve another objective, you reduced your CO(2) emission. So, if anyone was monitoring it, you could say, "Well, we have less CO(2) emission as a result of this purchase as well." Wouldn't that be fair?

A. Except you used the word "objective" in the middle of that sentence. That wasn't an objective.

Q. Quite correct. You would achieve a result?

A. Yes, a side effect.

Q. Side effect. The power that you were purchasing, that was from the United States, was it not?

A. Most of it, yes.

Q. And most of that power would be coal-fired generation; would it not?

A. When you purchase power, you do not know for certain where that power was generated. I

think it is fair to say, however, that the majority that we purchased would be produced by coal-fired generation.

Q. I wasn't asking you for a precise figure, but it is fair to say that, as you said, that the majority of it would be coal?

A. When one looks at the plant mix of our of neighbours with power for sale, yes, that's probably true.

Q. And, in effect, what we are doing with that is we are just, in effect, shifting the emissions from one jurisdiction to another, if you will. Isn't that fair way of looking at that?

A. That is correct, yes.

Q. Now, turning to another area, you mentioned purchases --

THE CHAIRMAN: If you are going to turn to another area, we probably should take the morning break.

MR. WATSON: Certainly, Mr. Chairman.

THE REGISTRAR: This hearing will recess for 15 minutes.

---Recess at 11:32 a.m.

...

---On resuming at 11:50 a.m.

THE REGISTRAR: The hearing has again resumed. Please be seated.

MR. WATSON: Q. Panel, we were talking about carbon dioxide emissions and I would like to continue. We just finished talking about purchases and I would like to turn now to NUGs.

If you look at the diagram which we were referring to, which is No. 5, you will see Case 15, as well as another graph that says Case 15 plus NUGs.

As I understand it, from figure 4.1 of the environmental analysis, which is on page 6 of Exhibit 145, we can see the annual atmospheric emissions from NUGs for NOx, SOx and CO(2), and -- well, we see NOx and SOx. The CO(2) line was very faded and didn't come through. Perhaps we could jointly draw that in now.

You can see that there is, for our purposes, there is a break at the line that is numbered 2 on the vertical axis over the year 2003. The CO(2) line goes, basically, from that break to just under 3 on the vertical scale.

And I believe, Ms. Ryan, you have figure 4.1 in front of you from the actual document and--

MS. RYAN: A. Yes.

Q. --I think that is correct, the line that I have described. It is almost a straight line?

A. Yes.

MR. WATSON: It is in the environmental analysis, as opposed to the DSP, Figure 4.1 on page 4.3. And as you will see, the line is a light yellow line. And unfortunately, it didn't photocopy very well, Mr. Chairman.

THE CHAIRMAN: All right. We have it.

MR. WATSON: Q. You will see for the year 2014, the CO(2) emissions for NUGs are approximately 3 teragrams per year and I understand that Hydro's emissions in 2014 are about 13 teragrams per year for Case 15. Is that correct, Ms. Ryan?

MS. RYAN: A. From the graph yes, it appears correct.

Q. Okay. Before I go any further, it is fair to say, in dealing with NUGs, that some of the NUGs are co-generation items which produce products other than electricity, and therefore, it is not fair to charge all of their emissions to production of electricity. But still, it is important to look at NUGs and their contribution to the effects of atmospheric emissions; is that fair?

A. They would have to be considered.

Q. Yes. And in looking at page 5, which is the Case 15, plus the NUG values added to it, it seems quite clear that any further expansion of NUGs would -- or a more rapid expansion of NUGs could result in a situation where the proposed target might not be met?

A. I think there are a couple of things that have to be noted here. One is that it is a proposed target and the more prevalent discussion now is in stabilization at the 1990 levels by 2005. The other is that NUGs would be a separate industry and would not be expected to be included within the Ontario Hydro cap for any given emission limit.

MR. SNELSON: A. The other comment I would like to add is that whether more NUGs lead to more CO(2) depends on what they substitute for.

Q. Could you expand upon that?

A. If you develop more NUGs that emit CO(2) and less hydraulic that does not emit CO(2), then CO(2) will go up.

If you develop more NUGs using natural gas as co-generation, instead of using existing coal-fired plant, then CO(2) will go down.

Q. Yes. Well, Ms. Ryan, you are making the point that the targets or the caps apply to Hydro

and that NUGs are a separate industry.

If, in fact, we adopt that sort of philosophy or thinking, then we are back to the situation that we were talking about earlier, when, in fact, the CO(2) target is in response to a global concern and we are trying to deal with CO(2) emissions throughout, not only the province, but the country and the continent. In effect, if Hydro is saying, well, the NUG emissions do not count against it, then wouldn't it be fair to say we do not really have an accurate assessment of what the total emissions are from the production of electricity?

MS. RYAN: A. I think you have to look at it much more broadly than the production of electricity, and that it is recognized that various industrial sectors have emissions. So, what the province or the country or the world, as a whole, has to do is determine what is an acceptable cap and then break it down ultimately into the industrial sector.

And so, I am not saying that NUG emissions of CO(2) would be ignored. They would be included in a larger perspective which would look at each industrial sector and determine what an appropriate limit would be for each sector for Ontario and Canada to meet its goal. So, it would be

considered, but not by Ontario Hydro.

Q. Just before we leave this, just so I am clear, the 20 per cent proposed target; is that an overall target on everyone, or is that just a Hydro target?

A. No. That was discussed as a target at an international protocol and it has not been agreed to by a number of governments, and our government is one of them, but it was looked at as the way we should be going. But certainly, nothing definite has been set.

Q. Okay.

A. But it is not an Ontario Hydro target; it is a far broader discussion point.

Q. Yes. If we could turn to the consideration of acid gases. You will see the next page of the exhibit, page No. 7 of Exhibit 145 deals with emissions of total acid gases under the median forecast, and in particular, it shows Case 26, as well as Case 26 with NUGs.

I understand from Case 26, that with scrubbers and low sulphur coal, you can meet the current SO(2) limits under Case 26; is that fair?

MR. SNELSON: A. I am not sure whether low sulphur coal is sufficient. There may, in some

cases in Case 26, be some assumptions about burning natural gas, but Case 26 can meet the emission limits with scrubbers and low sulphur fuels.

Q. Okay. My question was posed dealing with scrubbers and low sulphur coal, which you answered, but you have brought in a new topic of natural gas. Could you expand upon that and how that impacts on Case 26?

A. One of the strategies to meet acid gas emissions, which is higher cost than some of the other strategies, is to burn natural gas in existing plants. And natural gas, being a fuel which has virtually zero sulphur, then that is a very effective way of cutting down sulphur dioxide emissions.

Q. Ms. Ryan, we were talking earlier about the mandate of the Environmental Division.

These current limits, as far as the future is concerned, appear to stay constant after 1994. Can you help us as to where you think these limits are going to go in the future? Are they going to stay constant forever after 1994?

MS. RYAN: A. Certainly, based on the NOx/VOC management plan or protocol that you have referred to, it looks like there will be reduction requirements for NOx emissions which are part of total

acid gas. The way in environmental concerns have been going, it is fair to say that a further stepdown of acid gas limits in the future may happen.

Certainly, we do not have any regulations underway for the stepdown, but discussion has indicated that it may be considered in the future.

Q. And one of the protocols you were referring to was the NOx protocol, which calls for freezing of NOx emissions at the '87 level, I believe?

A. Yes.

Q. And for Hydro, that would be 62 gigagrams per year of NOx; is that correct?

A. That is correct. But in addition to that, there is a Ministry of the Environment initiative known as the NOx/VOC Management Plan, which is looking at NOx, as well.

Q. I was just about to refer to that, and they are talking about a lower limit on NOx of 40 gigagrams per year; is that fair?

A. They haven't specified a limit. The Management Plan looks the at a reduction of NOx in Ontario as a total, and various sectors having to step down. We do not have agreement with the Ministry, yet, on what ours is going to be.

Q. Well, the figure of 40 gigagrams per

year falls out of some of these current limits, does it not, because after 1994, the total amount is 215 gigagrams, I believe--

A. Yes.

Q. --for total SOx and NOx?

A. Yes.

Q. And 175 for SOx?

A. Yes. That is correct.

Q. Subtracting those two would leave a limit of 40 gigagrams for NOx; is that fair?

A. That is correct.

Q. Dealing with NOx, if you would turn to the next page which is another graph, entitled, "Atmospheric Emissions NOx for the Median Load Forecast" again, this is taken from your data and your graphs, and if there is any correction, please let me know.

This figure shows NOx emissions for Case 26 at median growth and it shows that the emissions are within the 62-gigagram-per-year limit, but appear to exceed the 40-gigagram-per-year limit. Is that fair?

A. Yes, though 40 is not yet a limit.

Q. I understand that; however, by 1994, you will have total limit of 215 on SOx and NOx and a limit of 175 on SOx?

A. That is correct.

Q. So, that if SOx are pushed to the total, you will have, in effect, a limit of 40 on NOx?

A. That is correct.

MR. SNELSON: A. I don't believe that is the correct interpretation of the current regulation.

The current regulation, I believe, permits more than 40 gigagrams of NOx, provided we emit a correspondingly lesser amount of SOx.

Q. Yes. No question, Mr. Snelson. I wasn't meaning to imply anything but that. I mean, your total is 215,000, but SOx, in fairness, has been singled out as having a limit within that 215?

A. Yes.

Q. And therefore, if you push that limit, you would have necessity to find a NOx limit?

A. If you are on the maximum for your SOx, yes.

Q. Yes, okay. And if, in fact, you do push that limit and you are at your 40 gigagrams per year for NOx, you are not going to be able to meet that with Case 26, are you?

MS. RYAN: A. We would meet our regulatory limit, because there is control technology for NOx that can be installed.

Q. So, you would either have to increase your costs by installing the NOx technology or not run some of the offending plants?

A. That is correct.

MR. SNELSON: A. The correct plan meets the current regulation, so to the extent that the plan 15 has more than 40 gigagrams of NOx, it has less than 175 gigagrams of SOx, so that it meets both the total limit and the SO(2) limit.

...

[11:02 a.m.] Q. One other question about Case 26. Isn't it fair to say that all of the new units proposed for Case 26 have SCR installed, NOx reducing SCR?

A. Yes. We selected new options to meet very high standards of environmental controls.

Q. And the other graph that is on that page shows Case 26 with NUGs added to it. And the NUG figures are taken from the same graph that we got the CO(2) figures from two pages earlier, that's figure 4.1 of the environmental analysis.

And, again, if my addition is wrong, I hope you will let me know, but in adding the NUG values to Case 26, you have a situation for a few years near the end of the plan where you are not meeting the 62-gigagram-per-year limit and an even longer period of time where you would be above the 40-gigagram-per-year limit.

MS. RYAN: A. Again, as with CO(2), it is not appropriate to add the NUG emissions to Ontario Hydro emissions and compare them to a hypothetical Ontario Hydro standard. We have options to lower our NOx emissions, and we would assume that if NOx reduction targets are required, that the NUGs industry would be regulated as well.

Q. I take that point, Ms. Ryan, and I

assume that is the Hydro position. But some intervenors might suggest that the total emissions resulting from the production of electricity should be considered, in which case, a graph such as this might be one way of looking at that.

A. And I agree it should be considered, just not necessarily in the form that you are doing.

Q. And if we continue on. A graph on page 10 is the same graph, only with respect to Case 15. And while Case 15 is below the protocol target of 62 gigagrams per year, even with NUGs added to it - and I take your point about that - even Case 15 does not meet the protocol target of 40, again subject to the discussion we had earlier about whether it might or might not occur.

A. Again, the Case 15 would not have appropriate control technology built into our existing units to meet a regulation which did not exist at that time.

Q. So, just dealing with that point in Case 15, you would, as we said earlier, either increase your costs for those plants that would require this further technology or you would, in effect, not run the plants that would put you over this target if you found yourself pushing the target of 40 gigagrams per year --

A. And it were regulatory limits, yes.

Q. Yes. And with respect to Case 26, the situation is somewhat different though, is it not, because you have already put SCR on all of your new units, so that, at least -- well, perhaps we should stop there. My understanding of Case 26 is that all of the new units coming on line will have SCR associated with them; is that correct?

MR. SNELSON: A. All the new base load units, but not the peaking units.

Q. Right. So, if, in fact, Case 26 has its base units with SCR already, that leaves you even less room to manoeuvre with respect to NOx emissions, does it not?

A. Yes.

Q. In fairness, I understand that Hydro is also looking at new injection technologies with respect to NOx emissions; is that correct?

MS. RYAN: A. Yes.

Q. SCRs are the process which will reduce NOx the most, but where do new injection technologies fit in? What sort of performance are you hoping to get from those?

A. I believe around 30 per cent, but it could be 30 to 50 per cent, depending on this specific

unit. There is a test plan to see what sort of reduction could be obtained, but again, if you want to get into detail of fossil control technology, Panel 8 would be better able to answer you.

Q. Okay. I will pursue that in Panel 8 then. I was going to ask you about the interaction of the new injection technology with the limits that we were discussing, 62 and 40.

Would you prefer that that question be deferred to the specific panels?

A. I think that would be better, yes.

Q. We will deal with that then.

I would like to turn to the next page and deal with - that's page 11 of Exhibit 145 - and deal with scrubbers. That is a chart that we had prepared from Hydro data that deals with efficiency, reliability and effectiveness. And just so that we all understand each other. As I understand it, efficiency is the percentage of SOx removed when the scrubbers are working properly; is that fair?

MR. TABOREK: A. Yes.

MS. RYAN: A. Mr. Taborek would be better suited to answer this.

MR. TABOREK: A. Yes.

Q. And reliability is the percentage of

time that each scrubber train is working properly and, in fairness, I believe Hydro has referred to that as "availability"?

A. Yes.

Q. The overall scrubber effectiveness is the percentage of SOx which is removed on average taking into account both the times the scrubber is working and the times it is not?

A. Yes.

Q. Mr. Taborek, could you help me out with just a first order approximation? Can we get a good idea of overall scrubber effectiveness by simply adding up the differences from a hundred, with respect to both the efficiency and the reliability? Does that give us a good first-order approximation?

A. Well, multiplying the first two gives the third.

Q. Multiplying the first two gives the third?

A. Yes.

Q. At the present time in the Hydro plan, do you expect to install any spare scrubber capacity, either on the existing units or the new units?

A. What is your definition of spare?

Q. For instance, if you had two scrubber trains dealing with a pair of units at one of your plants and they can deal with a hundred per cent of the emissions. If one of them goes down, you are not going to have anything in reserve. Is there any thought to, perhaps, building three scrubbers, so that if one goes down, you would still have two remaining?

A. No other options would fill that purpose.

Q. But not a scrubber option.

A. Not a scrubber, no.

Q. What other options would fill that purpose?

A. Generally lower sulphur fuels and an energy margin.

Q. I didn't hear that.

A. An energy margin.

Q. Could you elaborate on that, please?

A. Just as we have mentioned there should be a 24 per cent reserve margin for planning capacity for reliability purposes, we plan with a 9 terawatthour energy margin. And that, plus the other measures that we can take in place, aside from scrubbers, are designed to cater to energy contingencies.

MR. SNELSON: A. That was discussed in Interrogatory 2.7.66.

Q. Thank you.

Just before we leave that energy margin, if we could look at the reasons that that came about. Was that actually implemented with scrubber train inefficiency in mind, or was it more brought in because of concern, shall we say, with respect to some of the nuclear units or things like that?

MR. TABOREK: A. Like any margin, it is to cover anything that can happen to you, and those things can be things to the scrubber, things to the nuclear load, water, whatever.

Q. What would be a more probable event that this margin would deal with? A scrubber --

A. We haven't had any scrubbers, we have no scrubbers yet, so up until now, it has been dealing with load forecast uncertainties and nuclear production uncertainties.

Q. And so, if you have a 9 terawatthour energy margin when you have no scrubbers, if in fact you are going to use part of that margin to account for your scrubbers, you are going to have to increase that energy margin. Is that fair?

Or do you decrease the margin?

A. No, no, not necessarily. We review the margin from time to time, but it doesn't follow as you suggest.

Q. Well, it would follow, then, that if you brought scrubbers in, and if they used up part of the margin, then there would be less of a margin --

A. They don't use up -- okay, they are another contingency that the margin has to deal with.

Q. Yes.

MR. SNELSON: A. The base case on which the margin is added has assumptions in it about scrubber reliability and scrubber efficiency. So, the margin doesn't have to cover the fundamental expected amounts of unreliability and inefficiency from scrubbers; it only has to consider the variability about the expected scrubbers.

Q. So, in effect, scrubbers are in the margin?

A. In deciding what is the expected emissions in 1995, say, then the scrubbers in those simulations are modelled as having a certain reliability and a certain efficiency which leads to a certain effectiveness. So, the expected imperfections of the scrubbers are in the base case. And then we say we want our scrubber program to be able to handle

coal-fired or fossil-fired energy production, which is 9 terawatthours higher than that.

So, the base projection has the expected amount of imperfections of scrubbers built into it; the margin is only covering the variability about the expected amount of imperfections.

Q. And that variability includes scrubbers, so it is already being considered?

A. The expected inefficiency, the expected non-available times are incorporated in the base before the margin is added.

Q. Maybe it's Monday and I am just a little thick, Mr. Snelson. Perhaps I could just ask you a question, and I will say,"Answer yes or no," but you, of course, know that you don't have to answer yes or no, you can elaborate as much as you want.

But could you just tell me, yes or no, whether the scrubbers are in this energy reserve?

...

[12:20 p.m.] A. The scrubbers are one of the measures of meeting acid gas control, and that is to meet both the expected amount of fossil emissions and the allowance for additional energy, if required.

So, the scrubbers here are both part of the problem and part of the solution. They are much more part of the solution than they are part of the problem. If I install scrubbers, the situation gets better.

Q. Right.

DR. CONNELL: Mr. Watson, if it wouldn't be diverting you, could I just ask, is it important, in your judgment, that the panel understand all the entries in this table?

MR. WATSON: We are going to get to that, Dr. Connell, and I would suggest to you, yes.

DR. CONNELL: Yes.

MR. WATSON: The very simple answer to that question is, as the scrubber effectiveness changes, the amount of emissions changes as well, and that has a direct impact on any fossil option.

DR. CONNELL: Yes. Just as a general comment, it might have been easier or more accessible if it had had a caption on it and perhaps a little more detail in the legend.

MR. WATSON: Okay, I will keep that in mind for my future graphs. Thank you.

Q. Well, in any event, we will move on.

If a scrubber module fails, I understand that you can either keep running and emit more SOx and, in effect, operating in a bypass mode, or you can derate or shutdown the unit; is that fair?

MR. TABOREK: A. I think you would not derate; you would shut down. Yes.

Q. So, you either bypass and keep running or you --

A. And presuming the regulation would either permit bypass or not.

Q. Oh, yes.

A. There is no derating involved in that.

Q. What is your current assumption on out-of-service scrubber modules? Are you assuming that you will bypass and work within the limits?

A. Yes, we would bypass.

Q. So, that means, on average, the fraction of SOx that is removed by the scrubbers will be equal to what we have called overall scrubber effectiveness?

A. Yes.

Q. Now, could you tell me what overall scrubber effectiveness was assumed in the environmental analysis?

A. Which environmental analysis now?

Q. The environmental analysis which accompanied the Balance of Power.

MR. SNELSON: A. The amount of SO(2) emissions that were reported in the environmental analysis were provided from the system simulations that are described in the Demand/Supply Plan Report, Exhibit 3, and transferred over. So, the assumptions are those that are in the system simulation that were done for Plan 15 in the Plan Report, Exhibit 3.

Q. Okay. Could you tell me what that effectiveness is?

A. It would be in the LMSTM data, and Mr. Taborek may be familiar with what it is, but I haven't got the figure at my fingertips.

Q. Mr. Taborek, could you go through that big black manual of LMSTM and get me that answer?

A. We will have to take an undertaking.

Q. That would be 146.37.

THE CHAIRMAN: 142.37, isn't it?

MR. WATSON: 142.37, yes. Thank you, Mr. Chairman.

---Off the record discussion.

MR. WATSON: Q. Are you assuming that the scrubbers you put on the new units will be the same as the ones put on the existing units?

MR. TABOREK: A. Again, that will be something I will check.

Q. 142.38.

If you refer to the chart that I have put in front of you, on page 11, the first line says Thermal Cost Review, and the figures for efficiency, reliability and effectiveness were taken from that figure. Sorry, let me clarify that. The figures for efficiency and reliability were taken from that review.

As you said, Mr. Taborek, the effectiveness is obtained by multiplying the efficiency by the reliability. The thermal cost review in Table ES5 mentions a 90 per cent figure, as opposed to the 93 which would result when you multiply the efficiency by the reliability. Is this, in effect, a planning conservatism which is built in?

A. No, it's a different type of scrubber. The first line refers to a limestone dual alkali type of scrubber, the remaining four lines refer to limestone slurry scrubbers. A different reagent is used to remove the SO(2)

Q. And as a result, is the slurry necessarily somewhat less effective than the dual alkali?

A. Yes. If you would like to fill in the blanks on that line, the reliability is the same, about 95 per cent, the efficiency is 95 per cent.

Q. In the Acid Gas Control Reference Plan, you have indicated that you have reduced assumed scrubber reliability from 95 per cent to 90 per cent. That was for 1989.

When we reviewed 1990 Acid Gas Control Reference Plan we didn't see anything in that. Is it fair for us to assume that you have stayed with the same value of reliability, 90 per cent for 1990?

A. I will take an undertaking.

Q. That's 142.39.

Mr. Taborek, you have helped us out a lot by telling us that there is a difference between the scrubber numbers that are here. What sort of scrubber is going to be on Lambton, for instance?

A. The limestone slurry.

Q. And what sort of scrubber is proposed for the future units?

A. Nanticoke has not yet been decided; there is some consideration being given to the

limestone dual alkali; however, it may be the limestone slurry.

Q. What about new units that are built, has a decision been made?

A. I think we just described them in terms of their performance rather than their technical characteristics.

Q. So, a decision hasn't been made on which technology to use for the new units?

A. That's correct.

MR. SNELSON: A. There is probably an assumption in the thermal cost review but that would be something you would discuss with Panel 8.

Q. Yes, I believe the assumption is that there would be a slurry used. I'm sorry, I am corrected. The assumption apparently is that they would be dual alkali, but we will discuss that with Panel 8.

I was going to get into a discussion, more indepth discussion, about the actual efficiency of scrubbers and their reliability. Is that something that you people can deal with, or do you feel that the Panel 8 is more appropriate?

MR. TABOREK: A. Depending on how detailed, I can give you the general assumptions we use

about scrubber efficiency and reliability, and if you wish to go further, then, perhaps, I would refer to you Panel 8.

Q. Perhaps we could proceed along that basis.

Dealing first with efficiency, could you go through those basic assumptions?

A. Generally, there are three key assumptions. One is what is guaranteed, and then secondly, what might be expected for the limestone slurry and the limestone dual alkali.

Now, the efficiency specification for the limestone slurry is typically 90 per cent. The specification we would expect for the dual alkali is 95 per cent. It is recognized to be a more efficient scrubber.

In the case of the limestone slurry scrubber again, the expected performance is more in the nature of 95 per cent, but not guaranteed.

Q. Okay. when you say "performance" --

A. Efficiency.

Q. You are talking efficiency?

A. I am speaking strictly efficiency through this part.

Q. Okay.

A. And again, the expected performance of the dual alkali will be 98 per cent.

So, that's the respective efficiency of those scrubbers.

Q. Could we now turn to reliability and if you could go through the same exercise, please?

A. In reliability, in both cases we expect approximately 95 per cent. There is some history from the United States that well-designed scrubbers are doing much better than 95 per cent, and there is more experience with the limestone slurry than there is with the limestone dual alkali, so it's a firmer number.

Q. So, that 95 per cent figure is 95 across the board for dual and slurry, guaranteed and expected?

A. Yes.

Q. If I could, then, just refer you to the Acid Gas Control Reference Plan. Why in January 1989 did that plan reduce the reliability from 95 per cent to 90 per cent?

A. It was basically comparing the coincidence of outages of the scrubber and the thermal plant that led us to make a reduction of 5 per cent.

Q. Was that looking at historic data?

Is that a one-time reduction?

A. No, it was basically the size of the outage rates that we were looking at that have since been modified that led to us make an additional factor, or an additional adjustment.

Q. Thank you.

Now, I am a little at sea about that last answer. I am not sure I really understand what you are trying to convey to me. Could you try again, if you wouldn't mind?

A. Perhaps I will take an undertaking then. If I am confusing you, perhaps I am confused myself, and I will get an undertaking.

...

[12:35 p.m.] Q. I certainly have no difficulty with you taking an undertaking, Mr. Taborek, but just as a general rule, you should not assume that because I do not understand it, you are confused.

A. Well, you will notice I paused a fair bit, so...

MRS. FORMUSA: Is that 142 point...?

MR. WATSON: 142.40.

Q. Well, Mr. Taborek, if we could look at the '89 forecast of reliability indices, dealing with the reliability, we obtained a figure of 82 per cent by, in effect, taking a forced outage rate of 8 per cent and a planned or maintenance outage rate of 10 per cent. First of all, is that a fair way of looking at the reliability?

MR. TABOREK: A. For the scrubber itself, and assuming no bypass. But, it does not consider the fact that some of the outages would be coincident.

MR. SNELSON: A. It also doesn't take into account that some of the planned maintenance can be arranged at times when you didn't want to run the unit anyway.

Q. Just so I understand, was that what Mr. Taborek was talking about when he was talking about

coincidence?

A. No. I think there are two elements.

Q. Because that appears to be coincident. I mean, if you can arrange the two so they work together, that would seem to be optimum.

A. There is coincidence because the planned outage for the generating facilities maybe can be lined up with the planned outage for the scrubber, so as they overlap, you do not have to count both.

There are also times when you may not need to run that generating unit on the system, because there just isn't enough load. And you would attempt to do both scrubber planned maintenance and generating planned maintenance, whether or not they overlap, during the periods when you do not need to run the unit.

Q. We looked through the forecast for reliability indices and these were the only figures we could find. Is there some other indication of scrubber reliability in the forecast, other than what we have mentioned here?

MR. TABOREK: A. No.

Q. Based on the qualifications that you have just made, is there any way we can go from this 82 figure to a figure that would be more realistic, in

your mind?

A. Well, one step would be to use the 1990 reliability indices.

Q. Is there anything in there?

A. Yes. There are the same numbers, combined slightly differently.

The '89 values were basically produced by Hydro forecasting, and the '90 values were produced as a result of having called tenders and gotten improved information. And the information, basically the total incapability is reduced from about 18 per cent in the '89 reliability indices report to about 12 per cent with --

Q. And are you reading --

A. I'm sorry.

Q. Sorry to interrupt you, Mr. Taborek. I just wanted to clarify where you were. You were reading from page 3 of the explanatory notes of the 1990?

A. Yes. Generally, it is there, yes. I have extracted some of that information on your sheet here.

Q. I have it on page 3 under Item 1.3.5 at the last paragraph under the 1990 forecast of reliability indices.

MR. SNELSON: A. When you say "1990," is that the January 1990 issue?

Q. That is April 1991, the Report SP688. That is what you were referring to, was it not, Mr. Taborek?

MR. TABOREK: A. Yes. And on page 3, the third paragraph, you will notice --

THE CHAIRMAN: I am sorry. Page what?

MR. TABOREK: Page 3.

THE CHAIRMAN: Thank you.

MR. TABOREK: Third paragraph, the impact of scrubber operations without bypass is estimated at 7.5 per cent for DAUFOP and MOF and 5 per cent for POF, so those are our most recent forecast.

MR. WATSON: Q. As you indicated, in the 1989 forecast, the figures were 8 per cent and 10 per cent, giving a value of 82 per cent for reliability.

You have indicated that in '90, they have changed to 7.5 and 5 per cent, giving a value of 12-and-a-half per cent, which would change the 82 figure to 87.5; is that fair?

MR. TABOREK: A. Yes, yes.

Q. How do you --

A. And then you would have to allow for coincidence in outages.

Q. Okay. And you said the first step was to go to the more recent figures, which we have done. The second step is to allow for coincidence. Can you tell us how we would do that?

A. I think we have basically made some estimates that we would be looking at very small, perhaps negligible, outages as a result of the scrubber operation, perhaps negligible, perhaps as high as 5 per cent, but in that band. As a result, the recent experience with good, well-designed scrubbers has been of that nature.

Q. We are talking about coincidence here and you are giving us some other figures. Does bypass also play a role in those figures?

A. In that instance, the excellent reliability is with bypass.

Q. So, if there was no bypass, that would affect those figures?

A. Yes.

Q. The figures that you were dealing with earlier, when you were talking about reliability, you said 95 across the board for dual, slurry, with both guaranteed and expected values. Does bypass have an impact on those values?

A. Those are with bypass.

Q. With bypass. So, Mr. Taborek, if you are looking at the overall effectiveness, then we really cannot use the 95 per cent reliability figure, can we? We have to use a different figure to account for the bypass.

A. Well, you are assuming a regulation that does not permit bypass?

Q. Well, if, in fact, you wanted to operate without bypass, yes.

A. Yes. If you were doing that, you would.

Q. And the reason you would want to do that is so that you could have a handle on what total emission were?

A. Well, you always have the knowledge of what your emissions are. At present, you calculate them from the sulphur content of the coal, and in future, they will be monitored as they are emitted.

Q. Well, just before I leave this issue, the issue of bypass is significant because, as I understand it, dealing with the plan and dealing with the future units, you are putting scrubbers on, and in the future units, are you assuming bypass or are you assuming no bypass?

A. We are assuming that we will bypass.

Q. You will bypass?

A. Yes. What our regulation, PURPA, that now governs us is the total tonnes emitted over the course of a year by the system.

The prohibition of bypass is, in effect, putting a new regulation on us through the mechanism of the certificates given for the equipment and as a result - this is one of the examples I mentioned to you -- that regulations change fairly frequently and they can change the characteristics of your system, as a result.

MS. RYAN: A. Could I just add that, in addition to the emission cap that Mr. Taborek mentioned, there is still the modelling requirement that the design of the station would be required to meet specific impingement concentrations, even on bypass, so that limit would still have to be met.

Q. Mr. Taborek, if we are in an exercise where we are going to forecast what the emissions are going to be, you need to know what is happening with the scrubbers; is that fair?

MR. TABOREK: A. Yes.

Q. And is it also fair to say that in dealing with that issue, the figure to look at is the figure that you quoted of 7.5 for DAUFOP, MOF and 5 per

cent for POFs?

Q. No. I would recommend a scrubber efficiency of 95 per cent. A scrubber reliability of 95 per cent and a scrubber effectiveness of 90 per cent, which assumes bypass, as well.

Q. Thank you. In the course of your evidence, when you were talking about the efficiency, you mentioned the slurry had a guaranteed efficiency of 90 per cent and an expected efficiency of 95 per cent?

A. Yes.

Q. If, in fact, we use the 90 per cent guaranteed value for efficiency and the 95 per cent for reliability, that is going to give us a value somewhere below 90 per cent for effectiveness, probably around 86 per cent, something like that, 85 per cent; is that fair?

A. Yes.

Q. And correspondingly, any further decrease in efficiency below 95 per cent or below the 90 per cent that you spoke of for guaranteed, or below 95 per cent for reliability, is correspondingly going to decrease the overall effectiveness of the scrubbers; is that correct?

A. Yes.

Q. And just so we get an idea of the

difference in percentage, if we went from a 90 per cent overall removal rate to an 85 per cent overall emission removal rate, that would increase the overall SOx emissions by 50 per cent, would it not?

A. That is correct.

MR. SNELSON: A. From the scrubbed plants; not necessarily from the system.

Q. Yes, correct. Certainly, I am dealing with the plants here with scrubbers on them.

MR. TABOREK: A. Yes.

Q. So, a reduction from 90 to 85 increases the emissions by 50 per cent, and, correspondingly, if you went from 90 per cent to 80 per cent, the emissions would double?

A. Yes. Again, we are talking about forecasts which can err on one side. The experience with scrubbers recently has been improving, as more and more are built, and more and more experience is obtained with them. And there is work going on about additives and other measures for improving the efficiency of scrubbers and the same arithmetic, the same leverage, if you will, applies on the upside as the downside.

...

[12:50 p.m.] And so recognizing the concerns on the downside and recognizing potential on the upside, the 95/95 is a good set of numbers to use at the present.

Q. I suppose just following up on that, we have been dealing with Case 26 somewhat. If, in fact, you increased the SOx emissions by 50 per cent or doubled them, if your effectiveness was down to 80 per cent, that would put you significantly over the limit that was set for total acid gas emissions, would it not?

A. Yes. With the caveat, of course, that there is a law to be obeyed. If we found out that we were not in a position to obey the law, then we would take strong measures to ensure that we did.

Q. Yes. And we have talked about those measures before and I won't talk about them again.

Also, when you are talking about those measures, you are talking about not only a short-term measure, but you are talking about long-term measures as well, aren't you?

A. Appropriate to the problem you were experiencing, yes. Whatever you had diagnosed the problem that was giving you your reduced performance, you would take appropriate steps to solve it.

Q. A couple of quick questions. If you

could turn to page 12 of Exhibit 145, which is page 51 of the State of the Environment Report 1989, a quarter of way down the page, there is a mark and the sentence reads:

> "Results of a joint Canadian Electrical Association-Environment Canada project found that reported NOx emissions (based on optimum boiler conditions) are lower than measured emissions (based on as-found boiler conditions) by up to 30 per cent in some cases."

As I have read that, that would seem to imply that Hydro currently believes that your NOx emissions are higher than what they used to be. Is that a fair reading of that?

MS. RYAN: A. Not really. They are fairly close to what we had thought they were before, because there were some conservative assumptions in the way we used to calculate emissions. And based on the study, it was right across Canada, so it wasn't just our boilers, it was a general statement.

Q. Well, Ms. Ryan, I am not trying to trap you. I have got a couple of statements here that I don't understand and they seem to indicate different things.

If you can turn to the next page, which is page 13, which is the Response to Interrogatory 2.17.13.

A. Yes.

Q. Again, the part that is marked on the side. That seems to imply that calculations of NOx emissions which were used prior to recent testing were conservative. And when I read that, it seemed to indicate to me that the NOx estimates were lower than what you used to believe.

When I read the two statements together, I got different understandings or different meanings, and I was just wondering if you can clear that up for me.

A. On page 51, the Canadian Electrical Association tests found values up to 30 per cent higher than we had measured in tests when they just walked into a boiler and measured it.

Q. So, their test found that there was more there than you had thought?

A. For some units at some times, yes.

Q. Okay, great.

So, can we move to the next one then.

A. Yes.

Q. That seemed to me to imply that you

had less than you thought, less NOx than you thought?

A. There are two aspects to the problem. One is the way you measure it and the other is the way you calculate it. And we had conservative assumptions for calculating it which compensated for the error in measurement, so we ended up in about the same place.

Q. Were there any studies done to deal with that, to review that assumption that you are high one way, low the other way, and it all works out?

A. In fact, there were a series of tests carried out to do measurements on each unit and incorporate it into our calculation method, and that was approved by the Ministry of the Environment as the way in which we calculate and report our NOx emissions.

Q. Okay.

So, those aren't contradictory, they deal with different things, measurement versus calculation?

A. The first one is--

Q. Is measurement?

A. --is measurement, yes.

Q. And the second one deals with calculation, so that's the explanation?

A. Yes, because the assumption on the section page is the way it was calculated, which was conservative, so the first one is the first page you

referred to, page 51, is a measurement and the second one is the assumption in the calculation, which was conservative.

Q. They, in effect, offset?

A. To a large extent.

Q. Is this a function of load?

A. Yes. The way we used to calculate NOx emissions assumed that all of our megawatts was at full load which is a conservative assumption because NOx reductions are at higher loads. The way we do it now is have an algorithm that calculates it based on the actual load and what NOx would have been at that load.

Q. So, if you are varying your load, how does that affect the trade-off that you have?

A. If you are varying your load, your NOx emission rate is varying with load, it's lower at low load and higher at high loads.

Q. And in dealing with this measurement versus calculation trade-off, how is that sensitive to load? Does it always come out in the middle regardless?

A. We have changed our method of calculation so that we now base it on megawatts, which we have hourly megawatts for each unit, and we have NOx

tests at various loads for each unit and it's an algorithm that calculates NOx. It is a more accurate calculation now over the last two years, a year.

Q. One question, before we leave this area.

Is it fair to say, then, based on what you are saying about the new calculations, that for a base load unit, the calculation is going to result in a higher value?

A. Our fossil stations aren't base load.

Q. Okay. If a fossil was run at base --

A. For that assumption, yes.

Q. Thank you.

I am about to turn to another sub-area, Mr. Chairman, but I am very close to finishing the environmental area.

THE CHAIRMAN: Perhaps we should stop and come back at two-thirty.

THE REGISTRAR: This hearing will adjourn until two-thirty.

---Recess at 1:00 p.m.

...

---On commencing at 2:32 p.m.

THE REGISTRAR: Please come to order. This hearing is now resumed. Come to order.

MR. WATSON: Q. Panel, we were talking about scrubbers. If I could leave that now and move to particulates. I have a few brief questions.

In reading the DSP and some of the comments from the government on the DSP, I noticed a figure of 98 per cent dealing with the removal of particulates from fossil-fired units. Can you give me any indication of whether there is any current limit or target for particulate removal at Hydro?

You are looking puzzled, Ms. Ryan. I can give you the reference. It's page 14-19 of the plan, and it reads, Hydro has also installed emission control devices between the furnace and the stack, which typically remove over 98 per cent of the particulates?

MS. RYAN: A. The legal requirement for particulate would be under the Environmental Protection Act, and, again, is based on the ash content of the fuel, and precipitator efficiency, and is a modelled value to meet an impingement standard.

Q. Could you tell me where I would find that standard?

A. In the Environmental Protection Act.

Q. It's all set out there?

A. The value for groundlevel impingement would be, yes.

Q. Are there any other documents that you could refer me to, to assist me with this concept of particulate removal?

A. Not at this time, no.

Q. I understand in the United States, some of the jurisdictions have a 99 per cent minimum for the removal of particulates. Has Hydro investigated any further standards, further targets and whether they should be striving for something greater than 98 per cent figure?

A. One of the other limits would be the opacity which I referred to in my direct evidence and the amount of visible emission.

MR. SNELSON: A. The details about the precipitator efficiency that can be achieved are probably best addressed by Panel 8 in terms of what technology can achieve.

Q. I have looked at Interrogatory 2.2.8, which provides documentation relating to emissions and discharges from the natural environment. In particular, sulphur dioxide, nitric oxide, total acid gas and particulates. Is there any other source of

information besides this document, and is this the most up-to-date document which would give me those figures?

MS. RYAN: A. Of actual particulate emissions from our stations?

Q. Yes.

A. That is the current information and it would be based on precipitator testing for any given station.

Q. Can you tell me what emission rates were assumed for the new units to be built for particulates?

A. No, I'm sorry, I can't.

MR. SNELSON: A. I am just looking at your next sheet, which I thought had it on it. I expect that the solid wastes column is ash and not particulate.

Q. Just following up on that. I have understood that there was a difference between solid waste as a by-product from producing electricity and particulates; is that correct?

A. The particulates that are emitted are the ones that go up the stack that you don't collect. The fly ash, which becomes part the solid waste, are the ones that you do collect.

Q. Yes. And when we are globally

talking about the area of particulates, those are the things that go up the stack and that is what we are having our discussion about; was it?

MS. RYAN: A. Yes, particulate emissions, the ones that actually go out.

Q. You were talking opacity considerations. How are the limitations which have taken place, with respect to the output of Lakeview, Nanticoke, and Lambton, for opacity, related to particulate emissions?

A. There isn't really a one-to-one correlation between opacity and particulate emissions. Obviously, the more opacity that you can see, the higher the particulate emissions. But it depends on the specific size characteristics of the particulate, so you would have to do physical tests on a given unit to find the relationship. And I don't believe, at this point, we have those.

I know there have been studies done to do a correlation, but I don't have that information. Again, Panel 8 would have more information on precipitator characteristics.

Q. Can you tell me if there are any new particulate limitations being considered?

A. In Ontario, they were looking at a

more stringent opacity limit, in that it would be a 20 per cent limit all the time and not a small amount of time allowed at 40 per cent.

Q. Which is the current standard?

A. Which is the current standard.

Q. Anything else?

A. Not to my knowledge.

Q. If I could turn to toxic chemicals. I understand that heavy metal emissions are associated with coal combustion; is that correct?

A. Yes.

Q. And they are not currently dealt with; is that also correct?

A. Not entirely. Specific heavy metals are again regulated through the design of the station and the calculation of an impingement concentration. We do not have an emission cap for heavy metals the same as we do for acid gas.

Q. But what you are saying is you would recognize that the burning of coal or other fossil fuels might release some of these and as a result you design your plant to take care of those particular emissions?

A. The design of the plant up until this -- some of them are removed with the particulate

matter in the precipator, so that is correct. But the calculation I was talking about was calculating the result of an emission at stack height and what the concentration would be when it reached ground level. And that is regulated for some heavy metals, and yes, our stations would meet those.

As a matter of fact, Interrogatory 2.14.70, which was the Lakeview test you referred to, the table that you selected some of the information from, in fact, had all of the heavy metals that were tested for and listed there and their per cent of the impingement standard was calculated, and I believe most of them were under one per cent of existing regulation.

Q. We were talking about heavy metals, would 2.14.70 also deal with toxic organics and VOCs?

A. It measured organics, yes. Volatile organic compounds for Ontario Hydro are not generally a problem, but we measure them when we do our characterization studies.

Q. What do you mean, they are generally not a problem?

A. Well, the industries that are being looked at for volatile organic compound emissions are the petroleum industries, paint industries, solvents, because their emissions are considerably higher.

So, in talking NOx/VOC plan, NOx is the area we are concerned with. When it's VOC, they are talking different industrial sectors.

Q. Can you tell me if, currently, there are any further limits being considered for heavy metals, toxic organics, VOCs, and how these limits, if any, would affect Hydro's energy production in the future?

A. Yes, the Ministry of the Environment has issued a draft Clean Air Program which is a revision to Regulation 308 of the Environmental Protection Act, which in fact is looking at prevention at the source, and they have defined three different levels of concern for emissions and have identified specific heavy metals and organics which they would set emission limits for.

Again, it's a draft regulation. Industry has now provided comment and we haven't heard back whether or how that regulation is going to be changed, but some of the emission limits being proposed would be difficult for our existing fossil stations to meet.

Q. And all of that information is in the revision to Regulation 308 under the EPA?

A. It is called the Clean Air Program.

Q. You indicated Hydro might have

difficulty meeting certain of the limits, could you tell us which of the ones, currently, you might have difficulty with?

A. Several of the proposed heavy metals were manganese and mercury, and they were given a very small annual limit. They would be two of the limiting ones.

Q. And what effect would that have on your existing fossil plants?

A. If in fact we had to meet it and there were no control technology available to put in, it would mean curtailing generation.

Q. Is there, currently, controlled technology available?

A. I think the answer is we don't yet know how the scrubbers that we are putting in for sulphur dioxide might, in fact, affect the emissions of heavy metals, and we are hopeful that it will remove some of them. And certainly particulate control technology may remove some of the trace emissions, as well.

Q. Outside of that, do we have any particular technology that's focused in on heavy metals?

A. Not to my knowledge. But again, more

detail on fossil control technology could better be covered by Panel 8.

Q. Okay. If I can turn now to the Quebec City/Windsor corridor. During Environment Canada's review of the DSP, and an excerpt from that is at page 14 of Exhibit 145, approximately 40 per cent the way down the page, they mention the potential for more restrictive limits in this heavily-settled corridor. The limits mentioned for NOx are 100 nanograms per joule for coal; 90 nanograms per joule for oil, and 30 nanograms per joule for gas, to be effective by 1995, for new sources; and by 1997, for retrofitting of existing units.

And also, what it is mentioned earlier in the paragraph is VOCs. I didn't find any reference to VOCs when I looked through that. Is there one or did I just miss it?

A. In this total report?

Q. Yes. I just wondered if you were aware of a limit for them, because I didn't find one.

A. Could you tell me again what specific report this came from?

Q. This was Environment Canada's comments on the DSP. It doesn't have to be in here. I am just wondering if you are aware of something.

A. Yes. Actually in their NOx/VOC management plan, they have addressed NOx emissions and they have addressed separately VOC emissions, but, again, they are addressing different industrial sectors, not the electrical sector when they are talking VOC.

DR. CONNELL: Is this an exhibit, this document?

MR. WATSON: I think the government review is an exhibit.

THE CHAIRMAN: Is it the government review?

MR. WATSON: I believe so. I think it's the very end of the government review.

DR. CONNELL: You mean the provincial government review?

...

[2:50 p.m.] MR. WATSON: It is the provincial government review of the DSP, but at the back of it, I believe, Environment Canada has made their comments, as well.

THE CHAIRMAN: I cannot remember whether the government review is or is not an exhibit yet. Do you know? If it is not an exhibit, it probably should be, so perhaps we can -- we don't need to stop now and find that out, but if it isn't, we will put it in as an exhibit.

MRS. FORMUSA: I don't believe it is.

THE CHAIRMAN: I do not recall it being put in. I am sure it will be referred to at other times and it probably should be marked.

MR. WATSON: Okay.

THE CHAIRMAN: What part of the government review was it? Do you remember what exhibit it comes from?

MR. WATSON: If you are looking at the government review, the book I have, anyway, is a Cerlox binder.

THE CHAIRMAN: It's page 2, though.

MR. WATSON: This is page 2 of the Environment Canada section of that, which is at the end of the review put forward by all of the various

government ministries.

THE CHAIRMAN: All right, okay.

MR. WATSON: My copy, anyway, has a blue cover.

THE CHAIRMAN: Right.

MRS. FORMUSA: Should we make that an exhibit now?

MS. PATTERSON: Should we give it an exhibit number now?

THE CHAIRMAN: All right. We will give it a number now and then it will be done. What number is it?

THE REGISTRAR: 146, Mr. Chairman,

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 146: Review under the Environmental Assessment Act.

MR. WATSON: Q. Ms. Ryan, you will recall earlier, when we were talking about emissions, we referred to the State of the Environment Report, page 10, where we were talking about the emission standards of 258 nanograms per joule for NOx for coal, and 129 nanograms per joule as NOx for oil. And you recall that we were saying that Nanticoke and Lakeview now exceed the limit for both coal and oil. And in trying to compare that to the 100 nanograms per joule,

obviously, the 258 is considerably higher.

One of the efforts that would be made to try and control NOx, as I understand it, is low NOx burners; is that correct?

MS. RYAN: A. Low NOx burners are one way of reducing NOx, yes.

Q. And subject to your checking, I am advised that 100 nanograms per joule for a 35 per cent efficient plant translates to approximately 1 gram per kilowatthour of emissions. Again, subject to check, and please advise me if your calculations produce a different figure.

In looking at page 15, the last page of Exhibit 145, there are environment performance figures from the thermal cost review, figure ES5, for Option No. 2, which is a 4 by 500 megawatt U.S. coal unit, shows that NOx emissions with no scrubbers and no SCRs would be in the range of 1.2 to 1.5. Is that with or without low NOx burners, the Option No. 2?

MR. SNELSON: A. This is for new options, and it is presumed that new coal-fired plant would be designed from day one for low NOx and SO(2) emissions.

I do not think it is particularly relevant to the existing plant, where the control of

NOx in the combustion process in the design of the plant would be quite different perhaps to what a new option would be.

Q. Okay. So, in looking at those same figures, we can assume that there would be a low NOx burner for the first set of figures, 1.2 to 1.5.

The second set of figures 1.3 to 1.6; that is with a scrubber, but no SCR, and to get below the level 1 gram per kilowatthour, which is as I have been advised, what the hundred nanograms per joule translates to, you, in effect, would have to have a unit with scrubbers and SCRs, and low NOx burners alone would not be sufficient to meet this limit?

MS. RYAN: A. Yes. For our units to reach 100 nanograms per joule heat input would require SCR.

Q. And the last issue I would like to deal with, very briefly, is solid wastes.

In talking about Case 26, or any sort of life extension, we have been talking about the use of scrubbers. And I understand that it is fair to say that scrubbers produce a large volume of solid waste; is that correct?

A. Yes.

Q. And therefore, the use of Case 26 or

large-scale life extension is going to increase that quite substantially?

A. I think it is fair to say it should be considered a by-product because both the ash and the gypsum can have uses, so to consider it a waste is not exploring the utilization opportunities.

Q. Okay.

Mr. Chairman, I would like to turn to a new area, that of plant performance. And Mr. Lucas has another document for you in the same form with a document precis on the front of a series of excerpts including several tables.

THE REGISTRAR: That will be No. 147, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 147: Plant performance reference material to be used.

MR. WATSON: And again, Mr. Chairman, in particular in this section, as a result of my meeting with Hydro counsel on Friday, many of these questions have been deferred to another panel.

MR. WATSON: Q. So, Panel, in dealing with plant performance, if we could just start with some general questions on reliability indices.

I understand there are a variety of

indices which measure the reliability performance of a power plant, but is it fair to focus on four of these main indices: First of all, in no particular order, POFs, P-O-F; second of all --

THE CHAIRMAN: Perhaps you could, just for the uninitiated, just tell us what that is.

MR. TABOREK: Planned outage factor.

MR. WATSON: Planned outage factor.

THE CHAIRMAN: I know it has been said before.

MR. TABOREK: These are outages in which you have a long time in which to schedule them; typically more than a week, but anywhere in a year, really, for all practical purposes.

MR. WATSON: Q. And, Mr. Taborek, I have found the chart or the descriptions on page 36 of the 1990 Forecast of Reliability Indices of some assistance to me, as they describe all the various outages; the planned outage.

The next one I was to referred to, the MOF, the maintenance outage factor; the third one is DAFOR or DAUFOP, depending on whether you are talking about nuclear plants or fossil plants, assuming the fossils are on reserve at some times; and the forth factor is capability or incapability factor, depending

on how you look at it.

Is it fair to say that those are the four main factors?

MR. TABOREK: A. Yes.

Q. And the values, as well as the definitions, are published each year in the forecast of reliability indices?

A. Yes.

THE CHAIRMAN: What page was that on, did you say?

MR. WATSON: In the 1990, Mr. Chairman, it is on page 36. There is a series of definitions.

THE CHAIRMAN: All right.

MR. TABOREK: The whole of Section 4 of the report from page 33 through to page 36 gives varying levels of definitions of these indices.

DR. CONNELL: Of what exhibit?

THE CHAIRMAN: It is 1990. What Exhibit No. is 1990? 140, is it?

MR. WATSON: It was made an exhibit just at the start of Hydro's direct evidence.

MR. TABOREK: It is an Interrogatory 2.7.40. I am not aware of it being an exhibit.

THE CHAIRMAN: Oh, all right.

MR. WATSON: The 1990 forecast? It was

just introduced in evidence on Tuesday.

MRS. FORMUSA: No. That was the one that Mr. Shepherd objected to. I was filing it with respect to Interrogatory 2.2.22.

THE CHAIRMAN: Oh, yes. Did it get a number?

MRS. FORMUSA: No, it didn't. You will recall that we filed a list of interrogatories to which we might have to refer.

THE CHAIRMAN: Oh, yes. All right.

MRS. FORMUSA: It was not given an exhibit number, and the earlier versions of '88 and '89 were included behind 2.7.40 in that package.

So, all three of those reports from '88 to '90 were in response to two interrogatories in the package that our panel filed at the beginning, which was not given an exhibit number.

THE CHAIRMAN: I wonder if it should be, perhaps? I know we do not make interrogatories an exhibit. Should this one be an exhibit, do you think?

MRS. FORMUSA: This report?

MR. WATSON: I was going to refer to the concepts in this, and there may be some reference to some numbers in some of the earlier forecasts, as well as this one. We certainly can make it an exhibit, if

you would like.

THE CHAIRMAN: It is 2.7.40. Have you got it?

DR. CONNELL: Yes. Here it is, here.

MR. WATSON: So, Mr. Chairman, why don't we make it an exhibit?

THE CHAIRMAN: Obviously, I still haven't got right. If I look at page 36, it doesn't have anything.

MR. WATSON: Okay. If you are looking at 2.7.40, that will have the '88 and '89.

THE CHAIRMAN: Which one are you talking about?

MR. WATSON: If you look at part of the package that Hydro filed during their evidence, 2.2.22, you will see the '90 forecast.

MR. TABOREK: The earlier versions, the '89 report has the same definitions occurring between pages 32 and 35. It appears every year. It is a standard set of material.

THE CHAIRMAN: Okay. Everyone set now?

MR. WATSON: So, are we going to make 2.7.40 the next exhibit, which would be the '88 and '89 indices?

THE CHAIRMAN: Well, the one you are

referring to now is the '90. Do you intend to refer to the '88 and '89, as well?

MR. WATSON: I think all three of them are important, Mr. Chairman.

MS. PATTERSON: In response to Interrogatory 2.7.40, I have a report dated January 1990, that says 1989 Forecast of Reliability Indices, but I do not see 1988.

MR. WATSON: I could be wrong. I thought both of them were supposed to be attached to that interrogatory.

Q. Is that your understanding, Mr. Taborek?

MR. TABOREK: A. Yes.

MRS. FORMUSA: It should have been in that bundle.

MS. MORRISON: It is.

MS. PATTERSON: It is.

...

[3:05 p.m] THE CHAIRMAN: Well, why don't we make the '88, '89 and '90 forecasts one separate exhibit. How is that? We don't need to go through the paperwork right now; we'll just give it a number. Number...?

THE REGISTRAR: 148, Mr. Chairman.

THE CHAIRMAN: All right.

---EXHIBIT NO. 148: 1988/89/90 Forecasts of Reliability Indices for use in Corporate Planning Studies.

MR. WATSON: Q. Mr. Taborek, as I understand it, DAFORs are used for nuclear units; is that correct?

MR. TABOREK: A. Yes.

Q. And that measures the probability that a given unit will not be able to produce power during peak load periods?

A. Yes.

Q. And the DAUFOP, in effect, does the same thing for the fossil units?

A. Yes.

Q. Is it fair to say that the reserve margin is largely determined by the amount of capacity needed to reliably meet peak load?

A. Yes.

Q. And would you then agree with me that the DAFOR or the DAUFOP is the most important plant

reliability index for determining the required reserve margin?

A. Yes.

Q. Now in looking at peaking units, I understand their primary importance is to provide capacity?

A. Yes.

Q. And while they provide some energy, this is of less importance?

A. Yes.

Q. And for base load units, on the other hand, capacity is important but energy is also very important?

A. Yes.

Q. Now, in dealing with energy production, the most important measure of unit reliability is the incapability factor?

A. Yes.

Q. And that measures the fraction of a unit's theoretical possible output which cannot be produced due to equipment and regulatory constraints?

A. Yes.

Q. Now, if a plant has very cheap operating costs and no transmission line constraints, it will tend to always run at the maximum power of

which it is capable; is that fair?

A. Yes.

Q. And in that case, the plant's capacity factor will equal the capability factor or 100 minus the incapability factor?

A. Yes. And that's assuming there is adequate demand to require it.

Q. Yes.

And since a primary function of a base load unit is to provide energy, the incapability factors of base load units determine the number of units which are required; is that fair?

A. It will have an effect, yes.

Q. It will have a substantial effect, will it not?

A. A substantial effect.

Q. Is it fair to say that if all other things are equal, if the base load units have a higher incapability factor, they will produce less energy in a year and more units will be required to produce that energy?

A. Yes.

Q. Just two quick clarification points.

My understanding is that the '88 forecast of reliability indices was what was used in the DSP; is

that correct?

A. Yes. Yes, it was.

Q. And further I understand that the '89 forecast was used in the '91 reliability review?

A. Right.

Q. If I could ask you just a few questions on fossil unit DAUFOPs. As with the other figures, DAFORs, MOFs, POFs, the DAUFOPs come from these forecasts of reliability indices that we have been talking about.

A. Yes, they do.

Q. And those forecasts give us values for each unit or station for each of the next ten years but they also give us a "long-term average value," as well.

A. Yes.

Q. Now, Mr. Taborek, and the rest of panel, if you would turn to Table 1 of Exhibit 147,

DR. CONNELL: Once again, Mr. Watson, I presume these are percentages, but it doesn't so indicate on the table.

MR. WATSON: Yes, they are percentages, and Mr. Taborek can confirm that.

MR. TABOREK: Yes.

MR. WATSON: Thank you, Dr. Connell, we

will be sure to include that in future.

Q. Mr. Taborek, looking at Table 1, you will see it has values from the '88, '89 and '90 forecast. And I should tell you that these are average values for a station. The only one where it really comes into effect is Lakeview. And could we leave the figures so that, subject to your check, we will proceed?

MR. TABOREK: A. Fine.

Q. Now, from the '88 to the '89 forecast, the DAUFOPs are increasing except for Lennox. From '89 to '90, the DAUFOPs are roughly the same, save for Lakeview, where they continue to increase. Can you tell us, generally, why that is so?

A. It is essentially due to the amount of funding available. That the 1988 forecast was a forecast of adequate readily available funds.

In the '89 forecast, there were some general spending restraints that we were planning under and so there was a reduction of maintenance spending, resulting in a general increase in forced outage rates as a result of the general spending curtailment.

And in 1990, there was a particular reduction in -- or there was a limitation of spending on Lakeview, and Lakeview, in particular, increased in

that year. The others are essentially the same or very close to the '89 numbers. So, it's spending restraints from one year to the next.

Q. When you say spending, are you talking in a global context or are you talking specifically about OM&A?

A. For maintenance and for rehabilitation of the stations.

Q. We were talking earlier this morning about the Lakeview units, and they were found to be in worse shape than previously expected.

Now, I understand the rehab costs for Lakeview and Lambton have gone up and also that the costs schedules and the whole scope of the rehabilitation is under review with decisions expected sometime later this year.

A. That's correct.

Four of the units are going ahead with essentially a full rehab and four other units are being re-evaluated.

Q. Does the 1988 forecast reflect the conditions of these plants as you now understand them to be? And I would ask you the same question about the '89 forecast and the '90 forecast.

A. Well, I think each year reflected the

knowledge of the year, so that '88 and '89 would not reflect the now condition. There has been an extra year of knowledge accumulated in each case.

Q. Is it fair to say that that's one of the reasons why the Lakeview DAUFOP has increased so much because of your now greater understanding of what its condition is.

A. Yes, that would have led to an increased level of spending; and in curtailing the spending, that has the effect we have described, so the three are linked.

Q. In looking at the rehab plan for these units, is it fair to say that if all the previously planned work is not actually carried out, it would follow that the units after the rehab that is carried out would be in worse shape than previously anticipated or not as good shape as you would have hoped--

A. That's correct.

Q. --and therefore their performance would be poorer?

A. That's correct. The four units that have been fully rehabed will perform better than the four units that have not been.

Q. Can you tell me about Lambton? Is

that scheduled to be fully rehabed? And the reason I am asking you that is that I notice the DAUFOP doesn't change.

A. Yes. There have been some minor curtailments in Lambton's spending, on the spending on Lambton, but marginal compared to the curtailment at Lakeview.

Q. Now when you say marginal that is marginal in such a way that it is not going to affect the DAUFOP?

A. Yes, yes.

Q. If you can turn to Table 2, which are further DAUFOP numbers. And each of these forecasts gives numbers for the next, for the next ten years, and then a long-term average. And please notice that under the average, it is after rehabilitation.

A. Yes.

Q. So, in effect, what we have done is taken out the values for the next few years while they are under rehabilitation to try and get a more accurate real value for how the units will perform.

It appears as though Hydro is projecting virtually the same or a slightly improved performance in their fossil units throughout the remaining lives of these units; is that fair?

A. Yes.

Q. And we were talking before about the plants aging. Could you reconcile the long-term constant DAUFOP with the aging of these plants or is the answer the money that you just talked about?

A. I am not sure what you want me to reconcile. What versus what?

Q. As a plant ages--

A. Yes.

Q. --usually that would affect the DAUFOPs?

A. It could. There are circumstances where the DAUFOPS will improve and some where it will deteriorate. But okay, yes.

Q. Well, perhaps we can turn to the next page then which is entitled, "Lakeview DAUFOP Stylized."

A. I am just a little bit uncomfortable with the stylized. What I would like to do is put up the actual chart for Lakeview if I may. And you are referring I believe to the lower line?

Q. I think they both show the same pattern as the stylized curve and in effect what you have is over the last decade the performance has deteriorated and then there is going to be --

A. Over the last decade, okay. As I see it from, '71 to '81, '82, '83, there was a general improvement with age and then a sharp deterioration with age. And then with the sharp deterioration arrested by rehab programs, the traditional historical level is restored. That is how I would read that chart.

Q. Okay.

And the historical levels restored are, in effect, the constant DAUFOPs that you see on both--

A. Yes.

Q. --that chart that you are displaying on the overhead and also the stylized DAUFOP which is in Exhibit 147.

A. Yes.

Q. And it's fair to say, regardless of which one you look at, you expect an improvement in the DAUFOP after rehabilitation?

A. Yes.

Q. Which is evidenced by the fact that the level of DAUFOP is less than it was before the rehabilitation?

A. Yes.

Q. And also you do not expect any significant deterioration in performance of the plant

for the rest of its life.

A. And this is where money comes in. That there is an appropriate maintenance program to ensure that. Or that would have to be in place to enable that to happen.

Q. So that program is in place. You are putting or it is your intention to put the appropriate money into Lakeview so that the DAUFOPs remain constant over the rest of its life -- or its DAUFOP remains constant?

A. Well, there is a difference between a forecast and an intention. The forecast is that that is what the corporation will do and the reliability indices reflect that. The corporation may find itself in varying circumstances that it will or it won't. If we get improved intelligence as to the corporate intentions we will modify the forecasts.

And my forecasting like this can't make the company spend.

Q. I'm quite aware of that.

...

[3:20 p.m.] As presently advised, this is the Hydro plan?

A. Yes.

Q. And of course, there is no question that things may change and you may get overruled?

A. Yes.

Q. Now, I would like to explore that constant DAUFOP, a little bit, if I could. We have talked earlier about a planning life of 40 years, and given that you don't expect any additional major equipment problems, why do you expect the units to become economically obsolete after 40 years of operation?

A. I didn't say that we would not have further maintenance problems or equipment problems, is the phrase I think you used. I think that we would work to deal with them as they occurred.

Q. And assuming that you do, you are going to maintain your constant DAUFOP?

A. Yes.

Q. Assuming you do maintain that constant DAUFOP --

A. And, if I may, this is a forecast for 10 years. There is another 10 years beyond that which we will forecast when we get there and at that time we

will make appropriate forecasts for the beyond period.

Q. Well, in the forecast you not only forecast the next 10 years, you also have another column for long-term forecast; don't you?

A. But if you will notice that there is a change in the character in the last 10 years. In the first 10 years, there is a forecast for every year. In the 10-year and beyond period, it's a single number for all future years.

It's a reflection of the best present estimate, but it's indicating less confidence in the fidelity of the forecast in the long term with respect to those parameters.

Q. I understand you might not be as confident about those numbers. It's fair to say that the numbers are the same, though, the number for the long-term projection is the same as the last few years in this decade?

A. Yes.

Q. And again, that takes me back to my concern. If, in fact, your DAUFOPs as predicted seem to be to be the same, not only through this decade by long term, why do you expect the unit to become obsolete after 40 years of operation?

A. The word "obsolete" is not quite the

correct word.

The units will have basically reached the end of their service lives as a result of three factors bearing on the station. One is that to maintain reasonable performance with aging stations will require more money; two is there will be more economic alternatives available; and three, that environmental and other regulations will have evolved to the point where the station may not be environmentally acceptable.

Q. If any or all of those things are occurring as you go along your time line, isn't it fair to say that that's going to affect the amount of money that you are going to put into these units?

A. As each of these pieces of information becomes known we will evaluate whether it is appropriate to continue spending on the station or whether it is appropriate to replace it. If I may give you an example...

Q. Please.

A. We have spoken at some length about the NOx/VOCs regulations, and the form of the regulation, if it's a form that would require SCRs, selective catalytic reduction on Lakeview, then the station would become uneconomic, compared to replacing

with combustion turbine units.

Whereas, if the regulation confines those kinds of devices to stations that have a higher capacity factor and suits the low capacity factor, low energy output stations with a different type of NOx control, then the station may continue to be economic, and that is sort of independent to the wear and other factors that occur.

Q. Does that apply if, for instance, the coal units are going to be intermediate loaded?

A. Does that apply, could you qualify what you mean by "that"?

Q. Your explanation that you just went through. That may apply to a peaking unit.

A. If you mean does the potential for high capital costs put peaking stations more at risk than base load stations, the answer is yes, because you, basically, write off those costs on a base load station over many more megawatthours of energy production than over a peak station.

And the same, incidentally, holds true of a young station versus an old station. The timing of the regulation is similarly critical, because then you have, in the case of an old station, fewer years in which to write off your single capital investment.

Q. So, from that is it fair to say that putting an SCR on a base load unit is cheaper than using combustion turbine, for instance?

A. Yes. The economics would favour continuing to maintain the life of the higher capacity factor station.

And again, one has to be very careful and look at all the environmental regulations that are being applied and all of the effects at the time. I am very sensitive about environmental regulations because they change frequently, they change in many forms, and words and commas can make quite a difference.

Q. So, just to continue on with this. What you are saying is by looking at these three factors, greater money being spent, economic alternatives being available, environmental regulations changing, become more strict, that may very well affect the prediction of a constant DAUFOP to the end of a unit's life?

A. Yes.

MR. SNELSON: A. I don't think that we are predicting, in an absolute sense, constant DAUFOP to the end of the station's life. We have a simplification to the real world, and you seem to be trying to work backwards from the simplification to

impute something about the real world from what is really a simplification.

The simplification that we have made is that units continue operating in a normal and satisfactory manner at the long-term DAUFOP that is in the forecast, until its retirement date, and then, suddenly, it is taken out of service.

Now, that is a simplification to the real situation, which is that units will continue along, more or less in normal performance and acceptable performance, and, then, there will become indicators of either incipient problems sometime in the future, which may start to show up in current performance. And through a process that is hard to define at this time, there will be decisions made to retire, and the units over a period of time will be taken out of service. During that period of time, then, it is quite possible that performance may deteriorate significantly.

So, we have modelled something as though it is good performance and then it is suddenly taken out of service. In reality, it is going to be reasonably good performance and then some deteriorating service and gradually being replaced with some new capacity.

So, I don't think that you should assume

that what we have forecast is a precise prediction of how they will retire. It's an approximation to the retirement process.

Q. We have been dealing with Lakeview. Dealing with Lambton and Nanticoke, it appears as though you are projecting that future performance will be somewhat worse than recent history. Can you tell us why that is?

MR. TABOREK: A. Maybe the easiest thing is to... Lambton.

THE CHAIRMAN: Which table are you looking at?

MR. TABOREK: I will have to introduce these in evidence. They are not now in evidence in these forms.

THE CHAIRMAN: Wasn't that picture in before?

MR. TABOREK: What I showed you was the fossil system total before, sir. I have now broken the system down into the three plants, three main plants, Lakeview, Lambton and Nanticoke.

THE CHAIRMAN: Is that true of the one before as well, was it?

MR. TABOREK: Yes, it was, the Lakeview one.

THE CHAIRMAN: Perhaps two should be referred to by number.

MR. TABOREK: These three figures should go in. We need two numbers.

THE REGISTRAR: 149 and 150, sir.

THE CHAIRMAN: 149 is the graph that Mr. Taborek referred to in the last five minutes.

MR. WATSON: That would be the Lakeview incapability graph. And this is the Lambton incapability figure.

---EXHIBIT NO. 149: Lakeview Incapability Graph.

---EXHIBIT NO. 150: Lambton Incapability Graph.

MR. TABOREK: What this shows is the forced rates essentially maintain their historical levels, but there are slight increases in the total incapability, again after rehabing.

MR. WATSON: Q. I understand that you are again planning on spending substantial funds on the rehabilitation of Lambton?

MR. TABOREK: A. Yes.

Q. And could you tell us why you expect this decreased performance when you are spending these funds?

A. I think I would refer you to Panel 8 in that respect. And Nanticoke, you asked about

Nanticoke, as well?

Q. Yes.

THE CHAIRMAN: Was the answer the same for that?

MR. TABOREK: In this instance --

THE CHAIRMAN: That would be another number then.

MR. TABOREK: This will be the third.

THE REGISTRAR: 151.

---EXHIBIT NO. 151: Nanticoke Incapability Graph.

MR. TABOREK: And I don't view that as being significantly different from the recent history.

MR. WATSON: Q. So, in effect, you would analyze that in the same way that you did Lakeview?

MR. TABOREK: A. Yes.

Q. And the same factors would come into play?

A. Yes.

Q. And at the life you do not have a step function?

A. That's correct.

Q. You have a general winding down of --

A. There is a very dynamic set of decisions and processes that are going through in that time.

Q. Which evolve over time. And as you make those decisions you may run a plant for more than 40 years, especially if you put a lot of money into the plant and you have been able to maintain your DAUFOPs at a constant level.

That would be one of the decisions you would make, whether to life-extend, for instance?

A. Indeed. But the best number is 40. And we do say that having said 40, that there is a possibility of some units slightly more and some slightly less. And in the direct testimony we went into this at some depth.

Q. Yes. And the fallout from this would be, if you did have the constant DAUFOPs to the 40 year period and you decided to life-extend based on these factors that you have told us about, in particular, the three that you have mentioned, then that would have ramifications with respect to the building of new units?

A. Yes, it would.

But, I think I come back to the fact that at 40 years this is a long life for fossil units, it's longer than they were designed for, and we believe it to be the most appropriate life to use in planning.

...

[3:37 p.m.] Q. Just before you take that off, Mr. Taborek, you have "forced." Is that forced outage rates?

A. Yes.

Q. And "total"; that is the combination of force plus --

A. That is incapability.

Q. The total is incapability?

A. I wanted to avoid a lot of the jargon, and so I tried to simplify it in my prep material.

Q. Is it fair to say that incapability factors and DAUFOPs do not necessarily mirror each other during the course of a unit's life?

A. That is true. If you spend a good deal of time on maintenance, your incapability will be up, but the money well spent presumably will put the forced outage rate down.

As a matter of fact, it is not too evident there, but if we go back to the Lambton one, it is especially evident that there is a lot of planned maintenance, there is the forced outage creeping up, and then there, it is restored by the maintenance. That illustrates the effect.

Q. That is the incapability factors.

How about the forced outage rate and DAUFOP? What is the relationship between those over time?

A. Well, that is the same thing as I have said.

Q. As the incapability factor?

A. No, no, no. You said forced outage rate and DAUFOP?

Q. Yes. So, those are the same, as far as you are concerned, for the fossil unit?

A. Yes.

Q. Okay.

MR. WATSON: Now, Mr. Chairman, I just noticed the time now. It is twenty to four. I am in your hands as to whether you want to take a break. I am quite prepared to continue.

THE CHAIRMAN: How are you doing?

MR. WATSON: I am doing quite well, Mr. Chairman. I am quite confident that I will be finished today.

THE CHAIRMAN: Well, you have to stop around four-thirty, so will we take a 10-minute break? Will that do it?

MR. WATSON: Yes.

THE CHAIRMAN: All right.

THE REGISTRAR: The hearing will recess

for 10 minutes.

---Recess at 3:40 p.m.

---On resuming at 3:53 p.m.

THE REGISTRAR: Please come to order. The hearing is again in session. Please be seated.

THE CHAIRMAN: Mr. Watson?

MR. WATSON: Mr. Chairman, during the break, Mrs. Formusa had copies of Exhibits 149, 150 and 151 made, and I trust that you have those in front of you now.

THE CHAIRMAN: Yes.

MR. WATSON: Q. I just have a quick question with respect to Exhibit 150, Mr. Taborek.

MR. TABOREK: A. Yes.

Q. That is the Lambton incapability graph.

Just doing a rough estimate of that, looking at the forced figures at the bottom, it looks as though, if you average out the values after rehab and compare those to the average before rehab, the incapability seems a little bit higher; is that fair?

A. It depends what period. I think it might not be in the '80s, but I think it would be in the '70s, and I think probably overall, just eyeballing it, it would appear to be that way.

Q. Well, again, I do not want to put it any higher than that. I just eyeballed these figures and it seemed as though after you have done the rehab, it looks as though there is a little more incapability than before you did the rehab and I am just wondering if that is so, why that is so.

A. I can't answer that. I would refer you to Panel 8.

Q. Okay. I was going to ask you the same thing about the other ones, but I will deal with all of that in Panel 8.

A. Yes.

Q. If you could turn to Table 3, please, which shows fossil station OM&A costs in millions of 1990 dollars for three existing plants and one future plant.

As you can see, the data was obtained from interrogatories and a thermal cost review, and in fairness, we converted the 1986 and 1989 values to 1990 dollars, and the rate we used was 5 per cent for the conversion from '89 to '90, and 20 per cent for '86 to '90; in other words, 5 per cent a year.

Using those values, it appears as though there are large increases in OM&A for the three major existing coal stations. Can you tell us why that is

occurring?

A. Again, I think I would refer you to Panel 8.

Q. Table 3 also shows the OM&A costs for the existing stations appear to be higher than for the new stations. Would you prefer that we deal with that in Panel 8, as well?

A. Please.

Q. All right. And if I could take this opportunity to clarify one thing you said in your direct evidence.

I believe you mentioned that you were responding beyond rehabilitation, an extra $30-million a year and $20-million on Nanticoke.

A. Allow me to check. I thought it was 50 and 30, but I will just check. No. You are correct. It is 30 and 20.

Q. And is the 20 included in the 30 or is it separate?

A. Yes, it is included in the 30.

Q. So, of the $30-million per year that you are spending, 20 goes for Nanticoke and 10 goes for all the others?

A. Yes.

Q. And that is extra money beyond the

rehabilitation?

A. Yes.

Q. If you could turn to Table 4, which is a forecast of long-term DAUFOPs, the data is from the 1990 forecast and shows the forecast DAUFOPs for the existing stations is worse than the new stations. Can you tell us why that is so?

A. Again, I would refer you to Panel 8.

Q. Table 5, Panel, is a DAFOR forecast for the nuclear units and it is from the 1990 forecast and is averaged over the periods shown and it shows the units DAFORs improving through the '90s.

Maybe I am anticipating you, Mr. Taborek. I was going to ask you some questions on this. Do you want to deal with this or is this a Panel 9 issue?

A. Well, I will deal with it to the extent I can and I would propose to deal with it using similar material for the nuclear stations as I showed you for the fossil stations.

Q. Okay. Basically, I wanted to deal with the same analysis, if I could. The nuclear plants are, in effect, showing a constant DAFOR over their life -- sorry. They are showing an improving DAFOR over their lives through the '90s, except for Bruce "B", and --

A. Well, I think what I would like to do is put -- again, each of these will be an exhibit or is an exhibit. Each of these is new material.

THE CHAIRMAN: I think we should consign a number now, so if there's problems with reading the transcript, we will know what we are talking about.

THE REGISTRAR: Number 152.

THE CHAIRMAN: Number 152. Which is the...

MR. TABOREK: The Pickering incapability forced and total, Pickering "A" incapability, forced and total.

Now, what did -- you described --

---EXHIBIT NO. 152: Pickering "A" incapability, forced and total.

MR. WATSON: Q. Looking at Table 5, it appears as though the forecast DAFORs are decreasing over time.

MR. TABOREK: A. Well, I guess I would ask, compared to what period?

Certainly, the period from '83 to '89 in which units are forced out on their tubing, there was. But compared to the period '76 to '81, they are not. That period is better. And then, if you consider the whole, so I do not necessarily agree with the statement

you have made, if you look at all the years like that.

Q. I was simply looking at the forecasts that you put forward in your 1990 figures, which seem to indicate through the '90s, anyway, that the DAFORs are improving, if you will. They are getting smaller?

A. Well, I think that is a small change, but, yes, there is a small improvement. I view that as essentially returning to historical good levels.

Q. For instance, Bruce "A" is changing from 21.3 to 16.

A. Oh. Bruce "A".

Q. And Pickering "A" is changing from 18.3 to 15.3?

A. Yes, yes.

Q. Okay.

A. And here is the picture for Bruce "A", and I think it is quite similar to Pickering's, really. There is --

THE CHAIRMAN: Number?

THE REGISTRAR: 153.

---EXHIBIT NO. 153: Bruce "A" Incapability, Actual and 1990 Forecast.

MR. TABOREK: 153, Bruce "A". Then again, there is a similar picture of improving performance through the '70s and into the mid-'80s, and

then a deterioration and then a rehabilitation program being defined. And then, an improvement as a result of that and yes, a gradual improvement after that.

MR. WATSON: Q. Okay. And if we were to go through the same analysis that we went through with the fossil plants and looking at these factors for the life of the plant, again, you are not going to have a step function at the end of the 40-year planning life.

You are again going to look at the same sort of factors to determine what should be done with these units when they reach their 40-year planning life?

A. Yes.

Q. Is that fair?

A. Yes.

MR. SNELSON: A. The overall reason for the improving trend through the '90s is something we can tell you about. For the details, you would have to go to Panel 9.

But the overall reason is that through the 1980s, the late 1980s in particular, we have had significant deterioration in performance of our nuclear plant that has led to a backlog of work in things that require fixing, and it is not something which can be turned around in one year.

One of the things that is necessary to turn it around is more trained people and we have a program to hire a lot more people to operate and to maintain our nuclear stations, and the generally improving trend is the forecast that as those people are trained and become effective and they work on the backlog of things that need to be repaired and so on, that that will lead to an improving trend. But the details of that, you should address in Panel 9.

...

[4:04 p.m.] Q. Thank you.

So, in dealing with DAUFOPs or DAFORs, is it fair to say that any increase in those for the existing fossil or nuclear units would increase the required reserve margin?

MR. TABOREK: A. Yes.

Q. And, of course, increasing that reserve margin is primarily going to increase the need for, or accelerate the installation of, combustion turbines?

A. Yes.

MR. SNELSON: A. Or other generating capacity.

MR. WATSON: Thank you.

If I could have a minute please, Mr. Chairman?

---Off the record discussion.

MR. WATSON: Mr. Chairman, I was going to have a series of questions on various incapability factors of specific units which are referenced in Tables 6 and 7. Based on what the panel has said to date, I am going to defer those questions until Panel 8, unless they would like to deal with them today?

I take that as a "No," Mr. Taborek?

MR. TABOREK: A. Yes, that is a "No."

Q. The last table in this package is Table 8 dealing with nuclear unit incapability factors. Again, the data is from the '88, '89 and '90 forecast. And the historical data is taken from Hydro information supplied to NAERC. And I note that in the '88 and '89 forecasts, they both assumed 20 per cent average incapability factors throughout their remaining lives, and the 1990 forecast is somewhat different in that it shows an average of about 21.5, with factors varying between 20 and 23 per cent.

A. I can give you a summary and again introduce new material. This is the nuclear --

THE CHAIRMAN: Just wait until he asks you a question. That would be a good idea.

MR. TABOREK: Sorry.

MR. WATSON: Q. I was going to compare the various columns in Table 8. Column 4 shows the historic incapability factors and there appears to be a lot of scatter in these numbers. I assume that reflects the impact of the pressure tube problems?

MR. TABOREK: A. '85 to '89...

MR. SNELSON: A. It is partly pressure tube problems and it is partly some of the other smaller phenomena I was referring to. Pickering "A" is mostly pressure tube problems; Bruce "A" is not.

Q. What would it be?

MR. TABOREK: A. General wear.

Q. General wear.

And in future years, is it reasonable to expect that the impact of pressure tubes in these stations will continue to be substantial?

A. There will be defined retubing programs, so that all the reactors will be retubed in a cyclic fashion.

MR. SNELSON: A. And the retubing of existing reactors will be done in a way that is consistent with the way in which our current new reactors are being built and will incorporate all the measures that we now know of to either prevent or drastically slow the rate of deterioration of pressure tubes, so we expect that new pressure tubes will perform better than the existing pressure tubes in Pickering "A" and Bruce "A."

Q. So, there will be an impact due to pressure tubes, but it should be less than the impact you have experienced in the past?

A. The main impact over the next few years due to pressure tubes is planned outages to replace pressure tubes that are known to be deteriorating, and the phenomena and the details around

that program will be discussed in Panel 9.

Following retubing of any particular unit, then the performance is expected to improve and pressure tubes will be a very small part of incapability.

Q. Is it fair to say that the effect of pressure tubes has been to increase the incapability factor by approximately 10 per cent?

A. I haven't worked it out across the whole system. The impact has been quite high though, and particularly on Pickering "A" and to a lesser extent Bruce "A".

I mean, the order of magnitude is that in some years at Pickering "A," we had two units out of service for the whole year. So clearly on that particular station, the effect on incapability was 50 per cent.

Q. Do you have any figures for the future? Do you know whether the future or what the percent would be on the future impact of the pressure tube problem?

A. The Reliability Indices Report which we gave an exhibit number to, the 1991 version--

MRS. FORMUSA: 148.

MR. SNELSON: I am told it is 148.

--is our latest prediction of nuclear incapability and it includes the effects, the expected effects of pressure tube outages, both the planned outages for retubing and any unplanned effects that might occur either before or after retubing.

MR. WATSON: Q. Those effects are lumped together, though, are they not?

MR. SNELSON: A. Sorry, did you say they are lumped together or they are not lumped together?

Q. They are.

Is there a separate column for pressure tube effects?

A. The people who will testify to nuclear availability on Panel 9 should be able to give some indication of what proportion of that incapability is due to pressure tubes.

Q. I will pursue that with them then.

Is it fair to say then that looking at the 20 per cent incapability factor which you are basically predicting, that assumes, (1), the future impact of pressure tubes will be roughly as now predicted; and (2), the performance of the entire rest of the plant will be essentially comparable to your recent historical performance?

MR. TABOREK: A. Yes, with one proviso.

The retubing schedule has no more than one unit out through the 90s where this forecast is done. But in some periods, in the post-2000, I believe, there could be two units out at a time. So, that would be the additional effect. And yes, the work we are doing is intended to restore the historic levels of performance.

Q. In addition to the pressure tube problems, have there been any other major problems that have caused large outages and affected a substantial number of units?

A. Again while I can give you some information, I think the best source for it is Panel 9.

Q. Is it fair to say that the projection of an approximately 20 per cent incapability factor assumes there will continue to be miscellaneous problems affecting the rest of the other portions of the plant, aside from pressure tubes?

A. Oh, yes.

Q. However, is it also fair to say that 20 per cent incapability factor assumes there will not be any major generic equipment problems affecting these plants?

A. Yes.

Q. Is it fair to say that if you had another new problem with an impact only half as large

as a pressure tube problem, that future capability factors could be lowered from the 80 per cent level?

A. Well, again in the scale of the problems that we have dealt with up to this point in time aside from the retubing. And so if it were over and above that, yes, by definition.

Q. We were talking earlier about outages due to problems dealing with vacuum buildings. If there was a problem with a vacuum building, is it fair to say that could have a substantial effect on a capability factor?

A. Yes.

Q. Are problems such as vacuum tube problems encompassed in the present forecast?

A. Vacuum buildings?

Q. Yes, problems with the vacuum building?

A. There is provision, there is not a major outage due to a vacuum tube building failure.

MR. SNELSON: A. A vacuum...

MR. TABOREK: A. I picked up his "tube." Vacuum building being used, sorry.

MR. SNELSON: A. There are in the forecast outages, regular outages for vacuum building inspection, and all the systems that are associated

with vacuum building; and that is a regular occurrence at each station on about five yearly or thereabout cycle, and again Panel 9 can give you the details, but you may even be able to figure them out from the Reliability Indices Report.

Q. Have you had any outages like that in the past, vacuum building outages?

A. We have had vacuum building inspections, yes.

Q. But that would be something that you would have control over?

A. Yes.

Q. You haven't had an outage as a result of, a forced outage as a result of problems such as that?

A. Not to my knowledge.

Q. The 1989 consistent energy set talks about longer planned outages and adjustments to the reliability indices for many units. It appears to be partly related to the pressure tubes as well as SLAR, the Spacer Location and Relocation program.

The 1989 forecast, though, is essentially the same as the 1988 forecast at 80 per cent capability factors. Why is that in light of these comments in the consistent energy set?

MR. TABOREK: A. What was the date of the consistent energy set?

Q. 1989.

A. 1989. I'm sorry, I can't comment on the CES assumptions.

MR. SNELSON: A. Are you trying to compare the CES with a long-term availability forecast?

Q. Yes.

A. Because the CES is short term and these other forecasts we have been talking about are long term.

Q. Yes. But the CES is in effect talking about something that is going to occur in the future, it's talking about longer planned outages, and I was just curious as to whether -- the '89 figures appeared not to have been adjusted, and I was just curious as to why they were not.

MR. BARRIE: A. The consistent energy set only addresses the current year and the next five. It doesn't make any reference to anything longer than five years.

Q. I guess the question would then remain: Why wouldn't those five years be addressed in the '89 forecast?

A. I thought you were addressing longer

term forecasts up to this point.

Q. Well, five years is part of the long term --

MR. TABOREK: A. The answer in general is there is going to be a sequence that is gone through and that this information in the reliability indices, as I've mentioned, is prepared in the fall and issued early in the year.

And then the CES is performed at various points in the year, and they will update with whatever new information is available. Well, as the CESs are produced, as the next fall comes around, now the reliability indices are updated with new information, and I can only assume that there were changes in information in each of those steps.

Q. Before I leave this area, I would like to refer you to the Ontario Energy Board excerpts which are the last three pages of Exhibit 147. As you are aware, Panel, the OEB meets each year to look at a number of issues dealing with Hydro, and one of the issues being dealt with last year was the long-term performance capability factors of the nuclear units.

And you can see on page 98 of the report of the Board, under paragraphs 5.5.35, where Hydro noted in its argument - and again I note this is a

report of the Board, the Board summarizing Hydro's argument, if you will - it indicated that Hydro had substantial agreement with the MEA's submissions respecting capability factors and stated that as part of Hydro's annual review, it should take some of these factors into account. It also commented that the MEA's analysis of nuclear performance was a useful contribution to the subject.

Turning the page, you can see the recommendation of the Board, which is Recommendation 14, that Ontario Hydro reduce the lifetime capability factors for Pickering "A" and Bruce "A" to 75 per cent from 80 per cent.

And I guess my question would be if in fact lower capability factors are implemented for the nuclear units and for the coal units, this is going to increase the need for new base load plants; is that correct?

A. Yes.

...

[4:20 p.m.] Q. And this increased need is going to take place regardless of whether the reserve margin is 24 per cent or 20 per cent, or anything else; isn't that fair?

A. Allow me to consult, please.

MR. SNELSON: A. In general terms, you are right. There are some complications but in general terms.

Q. Thank you.

A. That was based on the premise that performance was being reduced.

Q. Yes.

A. Performance forecasts are being reduced.

Q. That the recommendation by the OEB was implemented, yes.

A. Yes.

MR. WATSON: That takes care of that area, Mr. Chairman.

I had some questions on coal supplies for existing plants. I understand from Mrs. Formusa that a fuels expert is being added to Panel 8, the fossil options panel, and as a result I will defer the questions to that...

MRS. FORMUSA: He is already on the

panel.

MR. WATSON: That person is already on the panel, so that appears to be a more appropriate place to deal with it.

Also, I had some questions on the hydraulic system, I will defer those to Panel 6.

I have a few quick questions on transmission. And if I could introduce...

Mr. Lucas, if you have this exhibit, if we could put that before the Board.

THE CHAIRMAN: Number?

THE REGISTRAR: It will be 154, Mr. Chairman.

MR. WATSON: Q. I have a couple of questions I could deal with before we get to that exhibit.

Mr. Taborek, if I could take you back very briefly to the F&D model. Does Hydro use the F&D model to evaluate the reliability of the east and the west system separately?

MR. TABOREK: A. No.

Q. So the whole system is done as a complete whole?

A. Total.

Q. The model is capable of doing those

separate runs, though?

A. Yes, you could model separate systems.

MR. SNELSON: A. We have in the past modelled the east system separately. We did not find it satisfactory as a model for the west system separately. And that's 10 years ago studies, but there is no reason to believe that it would be any different today.

Q. I understand that in the transmission product you have tables that present unreliability statistics by region. How does Hydro address any regional unreliability problems in planning for new generation?

A. Hydro, one of the factors in planning the transmission system is regional reliability in a general sense, though it's not accounted for generally in a probabilistic sense. And regional reliability and adequacy will affect the siting of generation.

MR. WATSON: Mr. Chairman, I have a table titled "Transmission Reliability Table," if I could have that made the next exhibit, please.

THE CHAIRMAN: Exhibit 154.

---EXHIBIT NO. 154: Transmission Reliability Table.

MR. WATSON: Q. Mr. Barrie, these

questions may perhaps be addressed to you.

In talking about transmission standards, I understand that one of the standards --

THE CHAIRMAN: It doesn't say on this table where this comes from. Oh, I see, yes, it does. I am sorry, it does say where it comes from. Go ahead.

MR. WATSON: Q. I believe one of Hydro's standards is to have no more than 15 per cent of its delivery points experience interruptions of greater than 50 effective minutes; is that correct?

MR. BARRIE: A. Yes, that's right.

Q. Now, this table shows under Column A a series of years and under Column B a series of numbers that attempt to show the per cent of delivery points that had interruptions greater than 50 minutes. Those figures were derived from an interrogatory from last year's rate hearing, Exhibit 6.6.62. Subject to your checking those figures, it appears as though only 1986 meets the standard.

Does that accord with your information?

A. Yes, that's correct.

Q. And in Column C we have figures for transmission maintenance which were obtained from Interrogatory 2.7.20, showing the amount of transmission maintenance spending over the last five

years. And in Column D we have the primary demand, 20 minute winter peak, again taken from Exhibit 7, page 57, which shows the demand increasing over the 5-year period.

The final column is the transmission maintenance in 1990 dollars, which is obtained by taking Column C, the amount spent on transmission maintenance, and dividing it by the peak in megawatts, and that gives a value which appears to be fluctuating somewhat, but overall is not increasing with the demand. And I was curious in looking at all those figures as to why Hydro has not been meeting the standard, and why more money has not been put into transmission maintenance?

A. Yes. Hydro has acknowledged at the OEB and at other places that we do wish to spend more money on transmission maintenance to improve the transmission performance.

As you say, we have since 1986 not been able to meet this particular standard and it is largely because of monetary constraints.

I should say that two major programs have been identified, though, to rectify the situation, and substantially increased expenditure on transmission maintenance is to be expected in the future. Probably

not a significant increase until about 1993, but from that point on significantly more money will be spent on transmission maintenance than has been the case.

Q. I propose to go, very briefly, back to a conversation that Mr. Snelson and I were having a day or two ago when we were talking about figure 5.1 of the reliability review, and if in fact the reserve margin was decreased from 24 to 21.6 per cent, it looked as though we could save about $29-million, and if, in fact, that $29-million was compared to what is currently being spent on transmission, that would be an increase of approximately 50 per cent, which I assume would go a long way toward improving that reliability situation; is that fair?

A. Is that a question?

Q. Yes.

A. $29-million additional expenditure per year would certainly go a long way towards improving these figures. In fact, the amounts I am talking about in these two programs I have referenced though is considerably more than $29-million.

Q. How much is it, Mr. Barrie?

A. It will be of the order of $100-million. The two programs are to refurbish both the transmission lines and do essential work at the

transmission stations and circuit breakers and transformers, and that kind of thing.

Q. Over what period of time is that $100-million to be spent?

A. The major expenditure, as I said, won't commence until about 1993. I have seen projections go for 10 years, but the work is likely to go on beyond that. This could be regarded as an ongoing program rather than a time limited program.

Q. But while the time is unlimited, the amount isn't, it's still $100-million.

A. Yes, there will be in excess of $100-million, over and above the expenditure that you see here.

MR. WATSON: Mr. Chairman, I know it's 4:30, but I have a few questions; I think I can finish quite quickly.

THE CHAIRMAN: Go ahead.

MR. WATSON: Q. If I could turn now, Panel, to NUGs with respect to transmission lines. I understand that Hydro currently has approximately 1200 megawatts of load displacement NUGs and 82 megawatts of purchase NUGs, and according to one of your interrogatories, all of the current NUGs are non-dispatchable; is that correct?

MR. BARRIE: A. Yes, that's correct.

Q. If a resource is non-dispatchable, doesn't this lead to less flexibility on the system?

A. Yes, that's correct.

Q. Now, I understand that transmission credit has been assumed as part of the payment to current NUGs. First of all, that's correct; is it not?

MR. SNELSON: A. Transmission credits are included as we feel appropriate to those NUGs which are in locations where we expect them to, in the long run, save transmission costs.

Q. And the level of the transmission credit is determined by Exhibit 84, the avoided cost determination for the 1989 Demand/Supply Plan?

A. Yes.

Q. So, you do an individual assessment as to whether specific NUGs should get the transmission credit?

A. That's something we were proposing to consider in Panel 3, as part of our avoided cost methodology.

We try to tailor-make the transmission credit to suit the particular situation, but there is a fair degree of complexity in that and that's perhaps better left to Panel 3.

Q. I was going to ask you whether Hydro had any recent problems where a NUG had caused transmission stability problems.

MR. BARRIE: A. Not that I am aware of.

Q. Are you aware of the problem with E.B. Eddy facility?

A. No.

Q. Perhaps I will deal with that at the later panel.

Q. And one final question dealing with interconnection assistance. We spoke about it in some length before. It's fair to say that Hydro feels that interconnections have a substantial benefit to the system and that's why they are in place.

Has there been any sort of transactional analysis as to the benefit of interconnections?

MR. SNELSON: A. Not in a comprehensive way. I can quote you a number as to the degree to which profits from export sales in the early 1980s reduced electricity rates, and for a number of years the reduction was around 6 per cent because of net profits from export sales. But that fluctuates.

MR. WATSON: Those are my questions, Mr. Chairman.

THE CHAIRMAN: Thank you.

Mr. Rodger, you will be tomorrow morning.

MR. RODGERS: Thank you, Mr. Chairman.

THE CHAIRMAN: Your estimate still stands?

MR. RODGERS: Yes, it does.

THE CHAIRMAN: Fine. We will adjourn until tomorrow morning at ten o'clock.

THE REGISTRAR: This hearing is adjourned until tomorrow morning at ten o'clock.

---Whereupon the hearing was adjourned at 4:35 p.m. to be resumed on Tuesday, May 28, 1991, at 10:00 a.m.